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August 1, 2005

BY OVERNIGHT DELIVERY AND E-FILE

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 05-27

Dear Ms. Cottrell:

Enclosed for filing, on behalf of Bay State Gas Company ("Bay State"), please find Bay State's responses to the following Record Requests:

From the Attorney General:

RR-AG-68

From the Department:

RR-DTE-85	RR-DTE-98	RR-DTE-101
RR-DTE-103	RR-DTE-104 (CD)	RR-DTE-106

Please do not hesitate to telephone me with any questions whatsoever.

Very truly yours,

Patricia M. French

cc: Per Ground Rules Memorandum issued June 13, 2005:

Paul E. Osborne, Assistant Director – Rates and Rev. Requirements Div. (1 copy)
A. John Sullivan, Rates and Rev. Requirements Div. (4 copies)
Andreas Thanos, Assistant Director, Gas Division (1 copy)
Alexander Cochis, Assistant Attorney General (4 copies)
Service List (1 electronic copy)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 05-27

Date: August 1, 2005

Responsible: Steven A. Barkauskas, Vice President Total Rewards

RR-AG-68: Who publishes the Moody's Aa Corporate Bond Index rate referenced in the second table on Attachment B of AG-19-16? Please explain how the nominal and annualized rates are calculated.

Response: The Moody's Aa Corporate Bond Index refers to the Moody's Aa Daily Long-Term Corporate Bond Yield Average published by Moody's Investors Service. The rates are published on the Moody's website at moodys.com.

The rates published by Moody's, and shown on Attachment B of AG 19-16 as "nominal rates," are semi-annual rates. The nominal rates were calculated by taking an average of the rates reported daily by Moody's for the month of September 2004. The rates were annualized using the following formula:

((1 + nr / 2) ^ 2) – 1.

For example, ((1 + .0573 / 2) ^ 2) – 1= .0581, or 5.81%.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 1, 2005

Responsible: Stephen H. Bryant, President

RR-DTE-085: AG-6-14 lists the number of new residential and business customers added from 1999 – 2005. Please provide a breakdown, by location, i.e. Brockton, Springfield and Lawrence.

Response: Table RR-DTE-85 (A) includes the requested information for residential customers, and Table RR-DTE-85 (B) provides the requested information for business customers.

Table RR-DTE-85 (A)

Residential

Year	Brockton	Springfield	Lawrence	Total
1999	2,135	1,301	582	4,018
2000	1,938	1,298	807	4,043
2001	1,682	687	388	2,757
2002	1,249	611	255	2,115
2003	1,129	596	289	2,014
2004	1,740	695	425	2,860
2005 YTD April	355	140	112	607

Table RR- DTE-85 (B)

Business

Year	Brockton	Springfield	Lawrence	Total
1999	308	212	50	570
2000	397	232	78	707
2001	398	185	56	639
2002	268	166	43	477
2003	296	84	44	424
2004	302	135	20	457
2005 YTD April	116	23	27	166

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 1, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

RR-DTE-98: Please indicate where the proposed revenue adjustments resulting from the fees referred to in Schedules JAF-1-7, JAF-1-8 and JAF-1-9 are factored into the Company's rate-year revenue in Schedules JAF-1-1, JES-4 and JES-5.

Response: As a correction to Mr. Ferro's testimony provided in response to cross-examination from the Bench during the hearing on July 22, 2005, the proposed revenue adjustments are not reflected in Schedule JAF-1-1, nor in Schedules JES-4 and JES-5. Schedule JAF-1-1 shows a summary of revenues beginning with the Company's books and ending with annualized (pro-forma) revenue at current rates. Revenues on Schedules JES-4 and JES-5 directly reference revenues on Schedule JAF-1-1. Schedules JAF-1-7, JAF-1-8, and JAF-1-9 are schedules that show proposed changes to existing rates that produce incremental revenue to the revenues shown on Schedule JAF-1-1, JES-4, and JES-5. Proposed incremental revenue of $34,855 for reactivation fees shown on Schedule JAF-1-7, $7,270 for warrants fees on Schedule JAF-1-9, and $4,400 for locksmith fees on Schedule JAF-1-9, totaling $46,525 is shown as a reduction to the base revenue requirement assigned to tariff customers in Schedule JAF-2-1, Line 208.

As Mr. Ferro testified on July 22, 2005, although Schedule JAF-1-8 proposes an increase of $40.00 for meters tested upon a customer's request (and when the meter tests accurately), there were no meter tests charged to customers during the test year and therefore none are projected into the rate year, resulting in no proposed revenue adjustment.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 1, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

RR-DTE-101: Please revise and submit the proposed annual base rate adjustment mechanism, M.D.T.E. No. 63, with the following changes:

(A) At the end of Section 6.0, on page 5 of 19, add the sentence, "The rate adjustment table in Section 11.0 shall be updated in the Company's subsequent ABRAM filings."
(B) At Section 7.2 (4), on page 6 of 16, add the phrase, "in DTE 05-27", after the word "Department" in both the second and fourth lines.
(C) At Section 7.3, on page 8 of 19, add the phrase, "in Section 11.0", to the definition of BR, superscript n,e, subscript T-1.
(D) At Section 9.2 (4), on page 12 of 19, remove the phrase, "prior to inclusion" and replace it with, "from the time those facilities are put into service up to the time included".
(E) At Section 9.5, on page 14 of 19, at the end of the first sentence add the word, "Requirements".
(F) At Section 9.5, on page 14 of 19, remove the phrase "avoided cost of leak repairs", and replace it with, "O&M offset to the costs of leak repairs".
(G) At Section 9.6, on page 14 of 19, add the word, "accumulated" before the word, "plant", in the definitions for both DEPR, subscript SIR and PTMS, subscript SIR.
(H) At Section 9.6, on page 15 of 19, add the phrase, "as approved in DTE 05-27", after the word, "return" and replace the word, "Accelerated" with the word, "Eligible" in the definition of CC, subscript SIR.
(I) At Section 9.6, on page 15 of 19, add the phrase, "as defined in Section 9.5.", at the end of the definition of SAV, subscript SIR.
(J) At Section 9.6, on page 15 of 19, replace the word, "Accelerated" with the word, "Eligible" in the definition of AGP subscript SIR.
(K) At Section 9.7, on page 15 of 19, replace the word, "base" (as used in the lower case only), with the word, "distribution".
(L) At Section 11.0, on page 17 of 19, replace the customer class designation, "OL" with "L".
(M) At Section 11.0, on page 19 of 19, add the missing rates in column (D).
At Section 11.0, on page 19 of 19, add the phrase, "and Section 7.3", to Note 3/.

Response: Please see the attached revised proposed Annual Base Rate Adjustment Mechanism, M.D.T.E. No. 63, tariff with the requested revisions, both in a clean (Attachment RR-DTE-101 (Clean)) and red-lined strikeout (Attachment RR-DTE-101 (Redline)) version.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

Section

1.0 Purpose

The purpose of the Annual Base Rate Adjustment Mechanism ("ABRAM") is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company") subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on an annual basis, its base rates for firm gas sales and firm transportation service pursuant to the Company's Performance Based Rate ("PBR") and Steel Infrastructure Replacement ("SIR") programs and to reflect the annualized impact of energy efficiency savings ("EES"). The PBR program encompasses a price cap rate indexing mechanism, as well as earnings sharing above and below established thresholds and recovery of exogenous costs. The SIR program provides for base rate adjustments that allow Bay State to recover the costs associated with accelerated replacement of bare and unprotected coated steel distribution mains and other Eligible Facilities. EES are the therm savings attributable to the installation of demand-side management ("DSM") measures pursuant to the Company's DSM programs as approved by the Department from time-to-time.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

2.0 Effective Date

The ABRAM shall be effective June 1, 2005 and shall continue subject to the terms of the PBR and SIR mechanisms set forth below. The initial rates established in accordance with Section 6.0 shall remain in effect until October 31, 2006. Subsequent base rate adjustments shall occur so long as either the PBR or SIR mechanisms remain effective or EES continue to be realized. In the event that both the PBR and SIR mechanisms are terminated and EES are no longer realized, the Company's base rates, as adjusted pursuant to the ABRAM, shall remain in effect until modified by the Department pursuant to a subsequent base rate proceeding.

2.1 Term of PBR Base Rate Adjustment Mechanism

The PBR Base Rate Adjustment mechanism shall continue for a term of five years through October 31, 2010. No further adjustment to the PBR component of the ABRAM shall occur after the completion of the five-year term ending October 31, 2010.

2.2 Term of SIR Base Rate Adjustment Mechanism

The SIR Base Rate Adjustment mechanism shall remain in effect until the Company's base rates are modified by the Department pursuant to a subsequent base rate proceeding.

3.0 Applicability

This mechanism shall apply an adjustment to the base rates of each of the Company's firm sales and firm transportation Rate Schedules, subject to the jurisdiction of the Department, as determined in accordance with the provisions of this mechanism. Such ABRAM shall be determined annually by the Company as defined below, subject to review and approval by the Department as provided for in this mechanism.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

4.0 Definitions

The following definitions shall apply throughout the provisions of the ABRAM tariff.

(1) **Base Rate Element** is any customer, volumetric or demand charge reflected in the Company's Rate Schedules that recovers a portion of the Company's base revenue requirement as established by the Department in its most recent base rate case.

(2) **Base Rates** are the compilation of Base Rate Elements for all of the Company's Rate Schedules

(3) **Calendar Year** is the annual period beginning on January 1st and ending on December 31st.

(4) **Customer Class** is the group of customers all taking service pursuant to the same Rate Schedule.

(5) **Energy Efficiency Savings** shall be the annualized therm savings attributable to energy efficiency measures installed during the Calendar Year.

(6) **Off-peak Period** is the continuous period from May 1st through October 31st.

(7) **PBR Adjusted Base Rate** is the base rate in effect for the Prior Year plus the rate change calculated through the application of the PBR Price Cap Formula to the base rates in effect for the Prior Year.

(8) **PBR Price Cap Formula** is the mathematical expression set forth in Section 7.3 used to calculate the percentage change in Base Rates for the Rate Year.

(9) **Peak Period** is the continuous period from November 1st through April 30th.

(10) **Prior Year** is the annual period ending immediately prior to the Rate Year.

(11) **Rate Year** is the annual period that the adjusted base rates shall be effective beginning on November 1st.

(12) **SIR Revenue Requirements** are the revenue requirements for the Company's SIR program for the Rate Year.

(13) **SIR Base Rate** is the total component of the Company's Base Rates that recovers the aggregate SIR Revenue Requirements for investments made over the duration of the SIR Program.

5.0 Annual Base Rate Adjustment Formula

The annual base rate adjustment formula shall be applied for each Base Rate Element of each Rate Schedule and shall be calculated in accordance with the following formula:

$$BR_{T}^{n,e} = (BR_{T-1}^{n,e} - BR\_SIR_{T-1}^{n,e}) \text{ x } (1 + PBR\_CAP_{T}^{n,e}) \text{ x } (1 + EE\_ADJ_{T}^{n,e}) + BR\_SIR_{T}^{n,e}$$

Where:

$BR_{T}^{n,e}$	The Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year
$BR_{T-1}^{n,e}$	The Base Rate Element *e* applicable to Rate Schedule *n* for the Prior Year
$BR\_SIR_{T-1}^{n,e}$	The SIR Base Rate for Base Rate Element *e* applicable to Rate Schedule *n* for the Prior Year
$PBR\_CAP_{T}^{n,e}$	The percentage change for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year calculated pursuant to the Company's PBR Program.
$EE\_ADJ_{T}^{n,e}$	The Energy Efficiency Adjustment Percentage for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year
$BR\_SIR_{T}^{n,e}$	The SIR Base Rate for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year

ANNUAL BASE RATE ADJUSTMENT MECHANISM

6.0 Determination of Initial Base Rates

The initial base rates shall be those established by the Department in Docket No. D.T.E. 05-27. The initial base rates shall be set forth in Column (I) of the Currently Effective Rate Adjustment Table contained in Section 11.0 to be effective through October 31, 2006. The first ABRAM change to the initial base rates shall be effective November 1, 2006. The Rate Adjustment Table contained in Section 11.0 shall be updated each year in the Company's annual ABRAM filings.

7.0 Calculation of PBR Annual Rate Adjustment

7.1 Description of PBR Program

The Company's PBR program replaces traditional cost of service ratemaking with an incentive-based mechanism. The PBR program includes price cap, earnings sharing and exogenous components. The price cap component limits the change in base rates to the rate of input price inflation representative of the gas distribution industry less offsets for productivity and a consumer dividend. The earnings sharing component provides for sharing of earnings that are outside symmetrical bands above and below Bay State's authorized Return on Equity. The exogenous cost component allows the Company to reflect costs or credits in the PBR mechanism that derive from unanticipated events that are beyond Bay State's direct control.

7.2 Definitions

(1) **Average Unit Price** shall be the price per therm calculated by dividing the total base revenues for the Customer Class for the Prior Year by the normalized annual throughput for the class for the Prior Year.

(2) **Basis Point** shall be one one-hundredth of a percentage point.

(3) **Consumer Dividend** is the benefit to consumers of future productivity gains attributable to performance-based ratemaking for Bay State's services as established by the Department in D.T.E. 05-27.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

(4) **Earnings Sharing Bandwidth** is the percentage range equal to 400 Basis Points below the percentage Return on Equity authorized by the Department to 400 Basis Points above the percentage Return on Equity authorized by the Department in D.T.E. 05-27.

(5) **Exogenous Events** are occurrences that have a material and disproportionate impact on Bay State that are beyond the Company's control and are not otherwise reflected in the PBR formula.

(6) **Input Price Trend** is the measure of change in the prices for all inputs used to provide regulated gas distribution services.

(7) **Productivity Trend** is the measure of change in productivity associated with providing regulated gas distribution services.

(8) **Return on Equity** is the allowed rate of return on equity as established in D.T.E. 05-27.

(9) **X Factor** is the productivity growth index as established by the Department in D.T.E. 05-27.

(10) **Z Factor** is the sum of the cost impacts of material Exogenous Events.

7.3 PBR Price Cap Adjustment Formula

$$PBR\_CAP_T = (GDPPI_{T-1} - X) + \frac{(Z_{REV} + ESM_{REV})}{(BASE\_REV_{T-1} - SIR\_REV_{T-1})}$$

and:

$$BASE\_REV_{T-1} = \sum_{n=1}^{n=i} \sum_{e=1}^{e=j} BR_{T-1}^{n,e} \times BD^{n,e}$$

ANNUAL BASE RATE ADJUSTMENT MECHANISM

and:

$$SIR\_REV_{T-1} = \sum_{n=1}^{n=i}\sum_{e=1}^{e=j} BR\_SIR_{T-1}^{n,e} \times BD^{n,e}$$

and:

$X = TFPT_{GDI\text{-}US} + IPT_{GDI\text{-}US} + CD$

Where:

PBR_CAP_T	The percentage change in the Average Unit Price for all Rate Schedules pursuant to Bay State's PBR Program.
$GDPPI_{T-1}$	The average annual percentage change in the United States Gross Domestic Product Price Inflation for the four most recent quarterly reporting periods as of the second quarter of the Calendar Year as published by the United States Department of Commerce.
X	The productivity or X Factor, which shall be the sum of the Productivity Trend differential, Input Price Trend differential, and the Consumer Dividend, as established by the Department in D.T.E. 05-27.
Z_{REV}	The sum of cost impacts of all Exogenous Events, positive or negative, as provided for in Section 7.5.
ESM_{REV}	The earnings to be shared with customers under the mechanism specified in Section 7.7.
$BASE\_REV_{T-1}$	The base revenues calculated by multiplying each Base Rate Element shown in Column (B) of the Currently Effective Rate Adjustment Table in Section 11 for each Company Rate Schedule, by the corresponding weather-normalized billing determinants for the most recent Calendar Year.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

SIR_REV_{T-1}	The SIR Revenues calculated by multiplying each SIR Base Rate shown in Column (C) of the Currently Effective Rate Adjustment Table in Section 11 for each Company Rate Schedule by the corresponding weather-normalized billing determinants for the most recent Calendar Year.
I	The total number of firm Rate Schedules to which the ABRAM is applicable.
J	The total number of Base Rate Elements for Rate Schedule *n*.
$BR^{n,e}_{T-1}$	The Base Rate Element *e* shown in Column (B) of the Currently Effective Rate Adjustment Table in Section 11.0 for Rate Schedule *n*.
$BD^{n,e}$	The most recent Calendar Year weather-normalized billing determinants corresponding to Base Rate Element *e* applicable to Rate Schedule *n*.
$BR\_SIR^{n,e}_{T-1}$	The SIR Base Rate *e* shown in Column (C) of the Currently Effective Rate Adjustment Table for Rate Schedule *n*.
TPT_{GDI-US}	The total Productivity Trend differential between the gas distribution industry in the Northeast and the overall United States economy as approved by the Department in D.T.E. 05-27.
IPT_{GDI-US}	The total Input Price Trend differential between the gas distribution industry in the Northeast and the overall United States economy, as approved by the Department in D.T.E. 05-27.
CD	The Consumer Dividend, as approved by the Department in D.T.E. 05-27.

7.4 PBR Annual Rate Adjustment

The Company may apply a non-uniform percentage change to each Base Rate Element of each firm Rate Schedule so long as the change in the Average Unit Price for the Customer Class is equal to the PBR Price Cap Adjustment. For purposes of calculating the Average Unit Price, the Company shall employ the weather-normalized billing determinants for the previous Calendar Year. The maximum percentage change to any individual Base Rate Element pursuant to the PBR mechanism shall be sum of the PBR Price Cap Adjustment and the X Factor.

7.5 Exogenous Events

The costs and/or cost reductions associated with unforeseen Exogenous Events that are beyond Bay State's control that occurred during the most recent Calendar Year and that are not reflected in the elements of the PBR price cap formula may be included in the PBR mechanism through the Z Factor. Examples of Exogenous Events are changes in tax laws that uniquely affect the local gas distribution industry, changes in accounting rules that uniquely affect the local gas distribution industry, and regulatory, legislative or judicial actions that uniquely affect the local gas distribution industry. Only material Exogenous Events, i.e. with cost impacts in excess of $600,000 positive or negative, shall be reflected in the Z Factor. The eligibility of the cost impacts of Exogenous Events for inclusion in the Z Factor shall be reviewed by the Department.

7.6 Revenue Exclusions

Base Rate revenue requirement items that are recovered through separate tracking mechanisms shall be excluded from the price indexing formula. The Company's SIR program costs described in Section 9 and Pension and Benefit Costs recovered through the Local Distribution Adjustment Clause shall be excluded from the PBR program.

7.7 Earnings Sharing

An Earnings Sharing component of the PBR program provides the Company and its Customers with protections in the event that the productivities achieved under the proposed program deviate materially from those anticipated and reflected in the PBR Price Cap Formula. In the event that the Company's actual Return on Equity for any annual period beginning January 1st of the years 2006 through the term of the PBR program is outside of the Earnings Sharing Bandwidth, the difference between actual earnings and earnings calculated at the authorized Return on Equity shall be shared 75%

to the Company and 25% to Customers. There shall be no earnings sharing when the Company's actual Return on Equity falls within the Earnings Sharing Bandwidth. The Company's net income and year-ending common equity balances as reported in its annual report to the Department shall be used to calculate the level of earnings sharing.

7.8 Information to be Filed with the Department

On or before June 1st of each year, the Company shall file information and supporting schedules with the Department necessary for the Department to review and approve the PBR Base Rate Adjustment to be included in the ABRAM for the subsequent Rate Year. Such information shall include the results of the calculation of the PBR Price Cap Adjustment Formula, descriptions and accounting of any Exogenous Events, and an earnings sharing calculation.

8.0 Calculation of Energy Efficiency Adjustment Factor

8.1 Applicability

The volumetric rates for firm Customer Classes that participate in the Company's energy efficiency programs shall be further adjusted to reflect the annualized impact of energy efficiency programs on the therm gas use of firm Customer Classes for the previous Calendar Year. The adjustment shall be calculated on a percentage basis for each Base Rate Element.

8.2 Determination of Energy Efficiency Savings

The Company shall calculate the therm gas use impact of the energy efficiency measures installed during the previous Calendar Year. The therm savings shall be annualized to reflect a full year's impact. The annualized therm savings shall be broken down by Customer Class and further disaggregated by Peak Period and Off-peak Period and by head and tail block, where applicable.

8.3 Energy Efficiency Adjustment Factor Formula

$$EE\_ADJ_{T}^{n,e} = \frac{BD^{n,e}}{BD^{n,e} - EE^{n,e}} - 1$$

Where:

$EE\_ADJ_{T}^{n,e}$ The Energy Efficiency Adjustment Percentage for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year

$BD^{n,e}$ The most recent Calendar Year weather-normalized billing determinants corresponding to Base Rate Element *e* applicable to Rate Schedule *n.*

$EE^{n,e}$ The annualized Energy Efficiency savings for the most recent Calendar Year associated with Base Rate Element *e* applicable to Rate Schedule *n.*

8.4 Information to be Filed with the Department

On or before June 1st of each year, the Company shall file information and supporting schedules with the Department necessary for the Department to review and approve the Energy Efficiency Adjustment to be included in the ABRAM for the subsequent Rate Year. Such information shall include a description of the energy efficiency measures installed and associated therm savings by Rate Schedule.

9.0 Calculation of SIR Base Rate Adjustment

9.1 Description of SIR Program

The Company's SIR program provides for the accelerated replacement of aging steel infrastructure in order to maintain safe and reliable service. The costs associated with the program less any operations and maintenance ("O&M") expense savings are recovered through the ABRAM.

9.2 Definitions

(1) **Accelerated Gross Plant Investments** are the capitalized cost of SIR plant investments including applicable overhead recorded on the Company's books that exceed the Non-Accelerated Investment Threshold.

(2) **Accumulated Deferred Income Taxes** is the net reduction in Federal income and State franchise taxes associated with the use of accelerated depreciation allowed for income tax purposes.

(3) **Accumulated Reserve for Depreciation** is the net credit balance arising from the provision for Depreciation.

(4) **Carrying Costs** are the costs incurred by the Company to finance investments in Eligible Facilities from the time those facilities are put in service up to the time included in the SIR Base Rate Adjustment mechanism.

(5) **Depreciation Expense** is the return of the Company's investment in Rate Base at established annual rates as approved by the Department in D.T.E. 05-27.

(6) **Eligible Facilities** are those facilities in connection with the projects undertaken by the Company to replace bare and unprotected coated steel distribution mains on an accelerated basis.

(7) **Non-Accelerated Investment Threshold** is the typical annual level of steel infrastructure replacement investment as established by the Department in D.T.E. 05-27.

(8) **Rate Base** is the investment value upon which Bay State is permitted to earn its authorized rate of return.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

(9) **Property Tax Rate** is the composite property tax rate paid by the Company calculated in its most recent base rate proceeding as the ratio of total annual property taxes paid to total net plant in service.

(10) **SIR Savings** are the O&M expense savings realized by the Company attributable to the facilities installed under the SIR Program.

9.3 SIR Investments

SIR Investments are the costs of Eligible Facilities and shall include the costs of main replacement projects including any connected facilities such as services, meters or regulators that must be installed or replaced to enable the main replacement to become operational. SIR Investments may include investments in one or more of the following plant accounts:

(1) Account No. 367, Transmission Mains
(2) Account No. 376, Distribution Mains
(3) Account No. 380, Distribution Services
(4) Account No. 381, Meters
(5) Account No. 382, Meter Installations
(6) Account No. 383, House Regulators
(7) Account No. 385, Industrial Measuring and Regulating Equipment

9.4 Eligible SIR Revenue Requirements

Eligible SIR Revenue Requirements shall include depreciation, property taxes, return and associated income taxes associated with total SIR Investments made since the initiation of the SIR program. Carrying Costs on SIR Investments from the time each investment is placed into service until recovery begins shall also be considered Eligible SIR Revenue Requirements.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

9.5 Eligible SIR Savings

Eligible SIR Savings shall be the lower O&M expense associated with reduced leak repair activity and shall be reflected as an offset to SIR Revenues Requirements. Eligible SIR Savings shall be calculated based on the reduction in the number of leak repairs and the associated O&M offset to the costs of leak repairs.

9.6 SIR Revenue Requirements Formula

$SIR\_REV_T = (RB_{SIR} \text{ x } PTRR) + DEPR_{SIR} + PTMS_{SIR} + CC_{SIR} - SAV_{SIR}$

and:

$RB_{SIR} = AGP_{SIR} - ARD_{SIR} - ADIT_{SIR}$

Where:

SIR_REV_T	The SIR Revenue Requirements for the Rate Year.
RB_{SIR}	The Rate Base associated with the SIR Program as of the end of the Calendar Year preceding the Rate Year.
PTRR	The pre-tax rate of return as established by the Department in D.T.E. 05-27.
$DEPR_{SIR}$	The depreciation expense associated with the accumulated plant investment in the SIR Program.
$PTMS_{SIR}$	The property taxes calculated based on the accumulated net plant investment in mains and services associated with the SIR Program multiplied by the Property Tax Rate.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

CC_{SIR}	Carrying Costs calculated monthly as the product of the Company's pre-tax rate of return as approved in D.T.E. 05-27 multiplied by the Eligible Gross Plant Investments associated with SIR Program plant placed in service, but not yet recovered through rates.
SAV_{SIR}	The total Eligible SIR Savings associated with reduced leak repair activity, as defined in Section 9.5.
AGP_{SIR}	The Eligible Gross Plant Investments associated with the SIR Program as of the end of the Calendar Year preceding the Rate Year.
ARD_{SIR}	The Accumulated Reserve for Depreciation associated with the SIR Investments as of the end of the Calendar Year preceding the Rate Year.
$ADIT_{SIR}$	The Accumulated Deferred Income Taxes associated with the SIR Investments as of the end of the Calendar Year preceding the Rate Year.

9.7 SIR Base Rate Adjustment

The SIR Revenue Requirements shall be recovered from Customers through each Base Rate Element of the Company's firm Rate Schedules by applying a SIR Base Rate Adjustment to each existing Base Rate Element excluding the SIR Base Rate for the Prior Year. The SIR Base Rate Adjustments shall be derived by allocating the overall SIR Revenue Requirements to each Base Rate Element by the percentage of Prior Year total distribution revenues associated with each Base Rate Element. The resulting revenues by each Base Rate Element are then divided by the corresponding weather-normalized billing determinants for the Prior Year to derive the SIR Base Rate Adjustment.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

9.8 Annual SIR Budget

In conjunction with its annual ABRAM filing each year, the Company shall provide the Department with a description of the SIR projects that it expects to complete during the current construction cycle and to include in the SIR Base Rate Adjustment for the following year. In addition, the Company will estimate the gross plant investment associated with each project. The list of projects and associated cost estimates shall be based on information available to the Company at the time it prepares the Annual SIR Budget and shall be provided for informational purposes. The specific projects undertaken during the current construction cycle and the associated cost of each project may vary due to circumstances and information that are not known by the Company at the time that the Annual SIR Budget was prepared.

9.9 Information to be Filed with the Department

On or before June 1st of each year, the Company shall file information and supporting schedules with the Department necessary for the Department to review and approve the SIR Revenue Requirements and the SIR Base Rates to be included in the ABRAM for the subsequent Rate Period. Such information shall include descriptions of all SIR Investments and the results of the calculation of the SIR Revenue Requirements Formula for the Rate Year. The Company shall also describe any factors that affected changes to the list of projects undertaken from those identified to the Department in the Company's Annual SIR Budget filed the previous year as well as any material variances in the project costs.

10.0 Information Required to be Filed with the Department

Information pertaining to all of the components of the Annual Base Rate Adjustment Mechanism is to be filed with the Department as specified in Sections 7, 8 and 9. In addition, the Company shall file revised tariff sheets reflecting the impact of applying the base rate changes provided for herein.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

11.0 Currently Effective Rate Adjustment Table

Customer Class And Charge	Previously Effective Rates			Currently Effective Rates				
	Base Rate	SIR Base Rate	Base Rate w/o SIR Base Rate	PBR ADJ %	PBR Adjusted Base Rate	Energy Eff. %	SIR Base Rate	TOTAL Base Rate
	Note 1/	Note 2/	(B) – (C)	Note 3/	(1+E) * (D)	Note 4/	Note 5/	(F) x (1 + G) + (H)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
R-1								
Customer Charge	$11.60	TBD	$11.60	TBD	TBD	TBD	$0.00	$11.60
Peak 0-12 therms	0.2393	TBD	0.2393	TBD	TBD	TBD	0.0000	0.2393
Peak 12+ therms	0.1928	TBD	0.1928	TBD	TBD	TBD	0.0000	0.1928
Off-Peak 0-10 therms	0.2393	TBD	0.2393	TBD	TBD	TBD	0.0000	0.2393
Off-Peak 10+ therms	0.1928	TBD	0.1928	TBD	TBD	TBD	0.0000	0.1928
R-2								
Customer Charge	$6.25	TBD	$6.25	TBD	TBD	TBD	$0.00	$6.25
Peak	0.1158	TBD	0.1158	TBD	TBD	TBD	0.0000	0.1158
Off-Peak	0.1158	TBD	0.1158	TBD	TBD	TBD	0.0000	0.1158
R-3								
Customer Charge	$12.10	TBD	$12.10	TBD	TBD	TBD	$0.00	$12.10
Peak 0-125 therms	0.3183	TBD	0.3183	TBD	TBD	TBD	0.0000	0.3183
Peak 90+ therms	0.2224	TBD	0.2224	TBD	TBD	TBD	0.0000	0.2224
Off-Peak 0-125 therms	0.3183	TBD	0.3183	TBD	TBD	TBD	0.0000	0.3183
Off-Peak 30+ therms	0.2224	TBD	0.2224	TBD	TBD	TBD	0.0000	0.2224
R-4								
Customer Charge	$6.25	TBD	$6.25	TBD	TBD	TBD	$0.00	$6.25
Peak	0.0708	TBD	0.0708	TBD	TBD	TBD	0.0000	0.0708
Off-Peak	0.0708	TBD	0.0708	TBD	TBD	TBD	0.0000	0.0708
L								
Per Light per Month	$2.58	TBD	$2.58	TBD	TBD	TBD	$0.00	$2.58
G-40								
Customer Charge	$19.00	TBD	$19.00	TBD	TBD	TBD	$0.00	$19.00
Peak	0.3090	TBD	0.3090	TBD	TBD	TBD	0.0000	0.3090
Off-Peak	0.3090	TBD	0.3090	TBD	TBD	TBD	0.0000	0.3090

ANNUAL BASE RATE ADJUSTMENT MECHANISM

	Previously Effective Rates			Currently Effective Rates				
Customer Class And Charge	**Base Rate**	**SIR Base Rate**	**Base Rate w/o SIR Base Rate**	**PBR ADJ %**	**PBR Adjusted Base Rate**	**Energy Eff. %**	**SIR Base Rate**	**TOTAL Base Rate**
	Note 1/	Note 2/	(B) – (C)	Note 3/	(1+E) * (D)	Note 4/	Note 5/	(F) x (1 + G) + (H)
(A)	**(B)**	**(C)**	**(D)**	**(E)**	**(F)**	**(G)**	**(H)**	**(I)**
G-50								
Customer Charge	$19.00	TBD	$19.00	TBD	TBD	TBD	$0.00	$19.00
Peak	0.2818	TBD	0.2818	TBD	TBD	TBD	0.0000	0.2818
Off-Peak	0.2818	TBD	0.2818	TBD	TBD	TBD	0.0000	0.2818
G-41								
Customer Charge	$65.00	TBD	$65.00	TBD	TBD	TBD	$0.00	$65.00
Peak	0.1920	TBD	0.1920	TBD	TBD	TBD	0.0000	0.1920
Off-Peak	0.1216	TBD	0.1216	TBD	TBD	TBD	0.0000	0.1216
G-51								
Customer Charge	$65.00	TBD	$65.00	TBD	TBD	TBD	$0.00	$65.00
Peak	0.1774	TBD	0.1774	TBD	TBD	TBD	0.0000	0.1774
Off-Peak	0.0826	TBD	0.0826	TBD	TBD	TBD	0.0000	0.0826
G-42								
Customer Charge	$213.00	TBD	$213.00	TBD	TBD	TBD	$0.00	$213.00
Peak	0.1794	TBD	0.1794	TBD	TBD	TBD	0.0000	0.1794
Off-Peak	0.0778	TBD	0.0778	TBD	TBD	TBD	0.0000	0.0778
G-52								
Customer Charge	$213.00	TBD	$213.00	TBD	TBD	TBD	$0.00	$213.00
Peak	0.1682	TBD	0.1682	TBD	TBD	TBD	0.0000	0.1682
Off-Peak	0.0657	TBD	0.0657	TBD	TBD	TBD	0.0000	0.0657
G-43								
Customer Charge	$781.00	TBD	$781.00	TBD	TBD	TBD	$0.00	$781.00
Peak	0.0507	TBD	0.0507	TBD	TBD	TBD	0.0000	0.0507
Off-Peak	0.0193	TBD	0.0193	TBD	TBD	TBD	0.0000	0.0193
Peak Demand	2.1586	TBD	2.1586	TBD	TBD	TBD	0.0000	2.1586
Off-Peak Demand	0.6713	TBD	0.6713	TBD	TBD	TBD	0.0000	0.6713

ANNUAL BASE RATE ADJUSTMENT MECHANISM

	Previously Effective Rates			Currently Effective Rates				
Customer Class And Charge	**Base Rate**	**SIR Base Rate**	**Base Rate w/o SIR Base Rate**	**PBR ADJ %**	**PBR Adjusted Base Rate**	**Energy Eff. %**	**SIR Base Rate**	**TOTAL Base Rate**
	Note 1/	Note 2/	(B) – (C)	Note 3/	(1+E) * (D)	Note 4/	Note 5/	(F) x (1 + G) + (H)
(A)	**(B)**	**(C)**	**(D)**	**(E)**	**(F)**	**(G)**	**(H)**	**(I)**
G-53								
Customer Charge	$781.00	TBD	$781.00	TBD	TBD	TBD	$0.00	$781.00
Peak	0.0507	TBD	0.0507	TBD	TBD	TBD	0.0000	0.0507
Off-Peak	0.0193	TBD	0.0193	TBD	TBD	TBD	0.0000	0.0193
Peak Demand	2.1586	TBD	2.1586	TBD	TBD	TBD	0.0000	2.1586
Off-Peak Demand	0.6713	TBD	0.6713	TBD	TBD	TBD	0.0000	0.6713

Notes: 1/ From Column (I) of the previous year’s Annual Base Rate Adjustment Filing Rate Table.
2/ From Column (H) of the previous year’s Annual Base Rate Adjustment Filing .
3/ Calculated in accordance with Section 7.3 and Section 7.4.
4/ Calculated in accordance with Section 8.3.
5/ Calculated in accordance with Section 9.7.
TBD – To be determined initially in the Company’s first Annual Base Adjustment Mechanism filing.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

Section

1.0 Purpose

The purpose of the Annual Base Rate Adjustment Mechanism ("ABRAM") is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company") subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on an annual basis, its base rates for firm gas sales and firm transportation service pursuant to the Company's Performance Based Rate ("PBR") and Steel Infrastructure Replacement ("SIR") programs and to reflect the annualized impact of energy efficiency savings ("EES"). The PBR program encompasses a price cap rate indexing mechanism, as well as earnings sharing above and below established thresholds and recovery of exogenous costs. The SIR program provides for base rate adjustments that allow Bay State to recover the costs associated with accelerated replacement of bare and unprotected coated steel distribution mains and other Eligible Facilities. EES are the therm savings attributable to the installation of demand-side management ("DSM") measures pursuant to the Company's DSM programs as approved by the Department from time-to-time.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

2.0 Effective Date

The ABRAM shall be effective June 1, 2005 and shall continue subject to the terms of the PBR and SIR mechanisms set forth below. The initial rates established in accordance with Section 6.0 shall remain in effect until October 31, 2006. Subsequent base rate adjustments shall occur so long as either the PBR or SIR mechanisms remain effective or EES continue to be realized. In the event that both the PBR and SIR mechanisms are terminated and EES are no longer realized, the Company's base rates, as adjusted pursuant to the ABRAM, shall remain in effect until modified by the Department pursuant to a subsequent base rate proceeding.

2.1 Term of PBR Base Rate Adjustment Mechanism

The PBR Base Rate Adjustment mechanism shall continue for a term of five years through October 31, 2010. No further adjustment to the PBR component of the ABRAM shall occur after the completion of the five-year term ending October 31, 2010.

2.2 Term of SIR Base Rate Adjustment Mechanism

The SIR Base Rate Adjustment mechanism shall remain in effect until the Company's base rates are modified by the Department pursuant to a subsequent base rate proceeding.

3.0 Applicability

This mechanism shall apply an adjustment to the base rates of each of the Company's firm sales and firm transportation Rate Schedules, subject to the jurisdiction of the Department, as determined in accordance with the provisions of this mechanism. Such ABRAM shall be determined annually by the Company as defined below, subject to review and approval by the Department as provided for in this mechanism.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

4.0 Definitions

The following definitions shall apply throughout the provisions of the ABRAM tariff.

(1) **Base Rate Element** is any customer, volumetric or demand charge reflected in the Company's Rate Schedules that recovers a portion of the Company's base revenue requirement as established by the Department in its most recent base rate case.

(2) **Base Rates** are the compilation of Base Rate Elements for all of the Company's Rate Schedules

(3) **Calendar Year** is the annual period beginning on January 1^{st} and ending on December 31^{st}.

(4) **Customer Class** is the group of customers all taking service pursuant to the same Rate Schedule.

(5) **Energy Efficiency Savings** shall be the annualized therm savings attributable to energy efficiency measures installed during the Calendar Year.

(6) **Off-peak Period** is the continuous period from May 1^{st} through October 31^{st}.

(7) **PBR Adjusted Base Rate** is the base rate in effect for the Prior Year plus the rate change calculated through the application of the PBR Price Cap Formula to the base rates in effect for the Prior Year.

(8) **PBR Price Cap Formula** is the mathematical expression set forth in Section 7.3 used to calculate the percentage change in Base Rates for the Rate Year.

(9) **Peak Period** is the continuous period from November 1^{st} through April 30^{th}.

(10) **Prior Year** is the annual period ending immediately prior to the Rate Year.

(11) **Rate Year** is the annual period that the adjusted base rates shall be effective beginning on November 1^{st}.

(12) **SIR Revenue Requirements** are the revenue requirements for the Company's SIR program for the Rate Year.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

(13) **SIR Base Rate** is the total component of the Company's Base Rates that recovers the aggregate SIR Revenue Requirements for investments made over the duration of the SIR Program.

5.0 Annual Base Rate Adjustment Formula

The annual base rate adjustment formula shall be applied for each Base Rate Element of each Rate Schedule and shall be calculated in accordance with the following formula:

$$BR^{n,e}_{T} = (BR^{n,e}_{T-1} - BR\_SIR^{n,e}_{T-1}) \times (1 + PBR\_CAP^{n,e}_{T}) \times (1 + EE\_ADJ^{n,e}_{T}) + BR\_SIR^{n,e}_{T}$$

Where:

$BR^{n,e}_{T}$	The Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year
$BR^{n,e}_{T-1}$	The Base Rate Element *e* applicable to Rate Schedule *n* for the Prior Year
$BR\_SIR^{n,e}_{T-1}$	The SIR Base Rate for Base Rate Element *e* applicable to Rate Schedule *n* for the Prior Year
$PBR\_CAP^{n,e}_{T}$	The percentage change for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year calculated pursuant to the Company's PBR Program.
$EE\_ADJ^{n,e}_{T}$	The Energy Efficiency Adjustment Percentage for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year
$BR\_SIR^{n,e}_{T}$	The SIR Base Rate for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year

ANNUAL BASE RATE ADJUSTMENT MECHANISM

6.0 Determination of Initial Base Rates

The initial base rates shall be those established by the Department in Docket No. D.T.E. 05-27. The initial base rates shall be set forth in Column (I) of the Currently Effective Rate Adjustment Table contained in Section 11.0 to be effective through October 31, 2006. The first ABRAM change to the initial base rates shall be effective November 1, 2006. The Rate Adjustment Table contained in Section 11.0 shall be updated each year in the Company's annual ABRAM filings.

7.0 Calculation of PBR Annual Rate Adjustment

7.1 Description of PBR Program

The Company's PBR program replaces traditional cost of service ratemaking with an incentive-based mechanism. The PBR program includes price cap, earnings sharing and exogenous components. The price cap component limits the change in base rates to the rate of input price inflation representative of the gas distribution industry less offsets for productivity and a consumer dividend. The earnings sharing component provides for sharing of earnings that are outside symmetrical bands above and below Bay State's authorized Return on Equity. The exogenous cost component allows the Company to reflect costs or credits in the PBR mechanism that derive from unanticipated events that are beyond Bay State's direct control.

7.2 Definitions

(1) **Average Unit Price** shall be the price per therm calculated by dividing the total base revenues for the Customer Class for the Prior Year by the normalized annual throughput for the class for the Prior Year.

(2) **Basis Point** shall be one one-hundredth of a percentage point.

(3) **Consumer Dividend** is the benefit to consumers of future productivity gains attributable to performance-based ratemaking for Bay State's services as established by the Department in D.T.E. 05-27.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

(4) **Earnings Sharing Bandwidth** is the percentage range equal to 400 Basis Points below the percentage Return on Equity authorized by the Department to 400 Basis Points above the percentage Return on Equity authorized by the Department in D.T.E. 05-27.

(5) **Exogenous Events** are occurrences that have a material and disproportionate impact on Bay State that are beyond the Company's control and are not otherwise reflected in the PBR formula.

(6) **Input Price Trend** is the measure of change in the prices for all inputs used to provide regulated gas distribution services.

(7) **Productivity Trend** is the measure of change in productivity associated with providing regulated gas distribution services.

(8) **Return on Equity** is the allowed rate of return on equity as established in D.T.E. 05-27.

(9) **X Factor** is the productivity growth index as established by the Department in D.T.E. 05-27.

(10) **Z Factor** is the sum of the cost impacts of material Exogenous Events.

7.3 PBR Price Cap Adjustment Formula

$$PBR\_CAP_T = (GDPPI_{T-1} - X) + \frac{(Z_{REV} + ESM_{REV})}{(BASE\_REV_{T-1} - SIR\_REV_{T-1})}$$

and:

$$BASE\_REV_{T-1} = \sum_{n=1}^{n=i} \sum_{e=1}^{e=j} BR_{T-1}^{n,e} \times BD^{n,e}$$

ANNUAL BASE RATE ADJUSTMENT MECHANISM

and:

$$SIR\_REV_{T-1} = \sum_{n=1}^{n=i} \sum_{e=1}^{e=j} BR\_SIR_{T-1}^{n,e} \times BD^{n,e}$$

and:

$$X = TFPT_{GDI\text{-}US} + IPT_{GDI\text{-}US} + CD$$

Where:

PBR_CAP_T	The percentage change in the Average Unit Price for all Rate Schedules pursuant to Bay State's PBR Program.
$GDPPI_{T-1}$	The average annual percentage change in the United States Gross Domestic Product Price Inflation for the four most recent quarterly reporting periods as of the second quarter of the Calendar Year as published by the United States Department of Commerce.
X	The productivity or X Factor, which shall be the sum of the Productivity Trend differential, Input Price Trend differential, and the Consumer Dividend, as established by the Department in D.T.E. 05-27.
Z_{REV}	The sum of cost impacts of all Exogenous Events, positive or negative, as provided for in Section 7.5.
ESM_{REV}	The earnings to be shared with customers under the mechanism specified in Section 7.7.
$BASE\_REV_{T-1}$	The base revenues calculated by multiplying each Base Rate Element shown in Column (B) of the Currently Effective Rate Adjustment Table in Section 11 for each Company Rate Schedule, by the corresponding weather-normalized billing determinants for the most recent Calendar Year.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

SIR_REV_{T-1}	The SIR Revenues calculated by multiplying each SIR Base Rate shown in Column (C) of the Currently Effective Rate Adjustment Table in Section 11 for each Company Rate Schedule by the corresponding weather-normalized billing determinants for the most recent Calendar Year.
I	The total number of firm Rate Schedules to which the ABRAM is applicable.
J	The total number of Base Rate Elements for Rate Schedule *n*.
$BR^{n,e}_{T-1}$	The Base Rate Element *e* shown in Column (B) of the Currently Effective Rate Adjustment Table in Section 11.0 for Rate Schedule *n*.
$BD^{n,e}$	The most recent Calendar Year weather-normalized billing determinants corresponding to Base Rate Element *e* applicable to Rate Schedule *n*.
$BR\_SIR^{n,e}_{T-1}$	The SIR Base Rate *e* shown in Column (C) of the Currently Effective Rate Adjustment Table for Rate Schedule *n*.
TPT_{GDI-US}	The total Productivity Trend differential between the gas distribution industry in the Northeast and the overall United States economy as approved by the Department in D.T.E. 05-27.
IPT_{GDI-US}	The total Input Price Trend differential between the gas distribution industry in the Northeast and the overall United States economy, as approved by the Department in D.T.E. 05-27.
CD	The Consumer Dividend, as approved by the Department in D.T.E. 05-27.

7.4 PBR Annual Rate Adjustment

The Company may apply a non-uniform percentage change to each Base Rate Element of each firm Rate Schedule so long as the change in the Average Unit Price for the Customer Class is equal to the PBR Price Cap Adjustment. For purposes of calculating the Average Unit Price, the Company shall employ the weather-normalized billing

ANNUAL BASE RATE ADJUSTMENT MECHANISM

determinants for the previous Calendar Year. The maximum percentage change to any individual Base Rate Element pursuant to the PBR mechanism shall be sum of the PBR Price Cap Adjustment and the X Factor.

7.5 Exogenous Events

The costs and/or cost reductions associated with unforeseen Exogenous Events that are beyond Bay State's control that occurred during the most recent Calendar Year and that are not reflected in the elements of the PBR price cap formula may be included in the PBR mechanism through the Z Factor. Examples of Exogenous Events are changes in tax laws that uniquely affect the local gas distribution industry, changes in accounting rules that uniquely affect the local gas distribution industry, and regulatory, legislative or judicial actions that uniquely affect the local gas distribution industry. Only material Exogenous Events, i.e. with cost impacts in excess of $600,000 positive or negative, shall be reflected in the Z Factor. The eligibility of the cost impacts of Exogenous Events for inclusion in the Z Factor shall be reviewed by the Department.

7.6 Revenue Exclusions

Base Rate revenue requirement items that are recovered through separate tracking mechanisms shall be excluded from the price indexing formula. The Company's SIR program costs described in Section 9 and Pension and Benefit Costs recovered through the Local Distribution Adjustment Clause shall be excluded from the PBR program.

7.7 Earnings Sharing

An Earnings Sharing component of the PBR program provides the Company and its Customers with protections in the event that the productivities achieved under the proposed program deviate materially from those anticipated and reflected in the PBR Price Cap Formula. In the event that the Company's actual Return on Equity for any annual period beginning January 1st of the years 2006 through the term of the PBR program is outside of the Earnings Sharing Bandwidth, the difference between actual earnings and earnings calculated at the authorized Return on Equity shall be shared 75%

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to the Company and 25% to Customers. There shall be no earnings sharing when the Company's actual Return on Equity falls within the Earnings Sharing Bandwidth. The Company's net income and year-ending common equity balances as reported in its annual report to the Department shall be used to calculate the level of earnings sharing.

7.8 Information to be Filed with the Department

On or before June 1st of each year, the Company shall file information and supporting schedules with the Department necessary for the Department to review and approve the PBR Base Rate Adjustment to be included in the ABRAM for the subsequent Rate Year. Such information shall include the results of the calculation of the PBR Price Cap Adjustment Formula, descriptions and accounting of any Exogenous Events, and an earnings sharing calculation.

8.0 Calculation of Energy Efficiency Adjustment Factor

8.1 Applicability

The volumetric rates for firm Customer Classes that participate in the Company's energy efficiency programs shall be further adjusted to reflect the annualized impact of energy efficiency programs on the therm gas use of firm Customer Classes for the previous Calendar Year. The adjustment shall be calculated on a percentage basis for each Base Rate Element.

8.2 Determination of Energy Efficiency Savings

The Company shall calculate the therm gas use impact of the energy efficiency measures installed during the previous Calendar Year. The therm savings shall be annualized to reflect a full year's impact. The annualized therm savings shall be broken down by Customer Class and further disaggregated by Peak Period and Off-peak Period and by head and tail block, where applicable.

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8.3 Energy Efficiency Adjustment Factor Formula

$$EE\_ADJ_{T}^{n,e} = \frac{BD^{n,e}}{BD^{n,e} - EE^{n,e}} - 1$$

Where:

$EE\_ADJ_{T}^{n,e}$ The Energy Efficiency Adjustment Percentage for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year

$BD^{n,e}$ The most recent Calendar Year weather-normalized billing determinants corresponding to Base Rate Element *e* applicable to Rate Schedule *n.*

$EE^{n,e}$ The annualized Energy Efficiency savings for the most recent Calendar Year associated with Base Rate Element *e* applicable to Rate Schedule *n.*

8.4 Information to be Filed with the Department

On or before June 1st of each year, the Company shall file information and supporting schedules with the Department necessary for the Department to review and approve the Energy Efficiency Adjustment to be included in the ABRAM for the subsequent Rate Year. Such information shall include a description of the energy efficiency measures installed and associated therm savings by Rate Schedule.

9.0 Calculation of SIR Base Rate Adjustment

9.1 Description of SIR Program

The Company's SIR program provides for the accelerated replacement of aging steel infrastructure in order to maintain safe and reliable service. The costs associated with the

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program less any operations and maintenance ("O&M") expense savings are recovered through the ABRAM.

9.2 Definitions

(1) **Accelerated Gross Plant Investments** are the capitalized cost of SIR plant investments including applicable overhead recorded on the Company's books that exceed the Non-Accelerated Investment Threshold.

(2) **Accumulated Deferred Income Taxes** is the net reduction in Federal income and State franchise taxes associated with the use of accelerated depreciation allowed for income tax purposes.

(3) **Accumulated Reserve for Depreciation** is the net credit balance arising from the provision for Depreciation.

(4) **Carrying Costs** are the costs incurred by the Company to finance investments in Eligible Facilities ~~prior to inclusion~~from the time those facilities are put in service up to the time included in the SIR Base Rate Adjustment mechanism.

(5) **Depreciation Expense** is the return of the Company's investment in Rate Base at established annual rates as approved by the Department in D.T.E. 05-27.

(6) **Eligible Facilities** are those facilities in connection with the projects undertaken by the Company to replace bare and unprotected coated steel distribution mains on an accelerated basis.

(7) **Non-Accelerated Investment Threshold** is the typical annual level of steel infrastructure replacement investment as established by the Department in D.T.E. 05-27.

(8) **Rate Base** is the investment value upon which Bay State is permitted to earn its authorized rate of return.

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(9) **Property Tax Rate** is the composite property tax rate paid by the Company calculated in its most recent base rate proceeding as the ratio of total annual property taxes paid to total net plant in service.

(10) **SIR Savings** are the O&M expense savings realized by the Company attributable to the facilities installed under the SIR Program.

9.3 SIR Investments

SIR Investments are the costs of Eligible Facilities and shall include the costs of main replacement projects including any connected facilities such as services, meters or regulators that must be installed or replaced to enable the main replacement to become operational. SIR Investments may include investments in one or more of the following plant accounts:

(1) Account No. 367, Transmission Mains
(2) Account No. 376, Distribution Mains
(3) Account No. 380, Distribution Services
(4) Account No. 381, Meters
(5) Account No. 382, Meter Installations
(6) Account No. 383, House Regulators
(7) Account No. 385, Industrial Measuring and Regulating Equipment

9.4 Eligible SIR Revenue Requirements

Eligible SIR Revenue Requirements shall include depreciation, property taxes, return and associated income taxes associated with total SIR Investments made since the initiation of the SIR program. Carrying Costs on SIR Investments from the time each investment is placed into service until recovery begins shall also be considered Eligible SIR Revenue Requirements.

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9.5 Eligible SIR Savings

Eligible SIR Savings shall be the lower O&M expense associated with reduced leak repair activity and shall be reflected as an offset to SIR Revenues Requirements. Eligible SIR Savings shall be calculated based on the reduction in the number of leak repairs and the associated O&M offset to the ~~avoided~~ costs of leak repairs.

9.6 SIR Revenue Requirements Formula

$$SIR\_REV_T = (RB_{SIR} \text{ x } PTRR) + DEPR_{SIR} + PTMS_{SIR} + CC_{SIR} - SAV_{SIR}$$

and:

$$RB_{SIR} = AGP_{SIR} - ARD_{SIR} - ADIT_{SIR}$$

Where:

SIR_REV_T	The SIR Revenue Requirements for the Rate Year.
RB_{SIR}	The Rate Base associated with the SIR Program as of the end of the Calendar Year preceding the Rate Year.
PTRR	The pre-tax rate of return as established by the Department in D.T.E. 05-27.
$DEPR_{SIR}$	The depreciation expense associated with the accumulated plant investment in the SIR Program.
$PTMS_{SIR}$	The property taxes calculated based on the accumulated net plant investment in mains and services associated with the SIR Program multiplied by the Property Tax Rate.

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CC_{SIR}	Carrying Costs calculated monthly as the product of the Company's pre-tax rate of return as approved in D.T.E. 05-27 multiplied by the Eligible ~~Accelerated~~ Gross Plant Investments associated with SIR Program plant placed in service, but not yet recovered through rates.
SAV_{SIR}	The total Eligible SIR Savings associated with reduced leak repair activity, as defined in Section 9.5.
AGP_{SIR}	The ~~Accelerated~~ Eligible Gross Plant Investments associated with the SIR Program as of the end of the Calendar Year preceding the Rate Year.
ARD_{SIR}	The Accumulated Reserve for Depreciation associated with the SIR Investments as of the end of the Calendar Year preceding the Rate Year.
$ADIT_{SIR}$	The Accumulated Deferred Income Taxes associated with the SIR Investments as of the end of the Calendar Year preceding the Rate Year.

9.7 SIR Base Rate Adjustment

The SIR Revenue Requirements shall be recovered from Customers through each Base Rate Element of the Company's firm Rate Schedules by applying a SIR Base Rate Adjustment to each existing Base Rate Element excluding the SIR Base Rate for the Prior Year. The SIR Base Rate Adjustments shall be derived by allocating the overall SIR Revenue Requirements to each Base Rate Element by the percentage of Prior Year total distribution ~~base~~ revenues associated with each Base Rate Element. The resulting revenues by each Base Rate Element are then divided by the corresponding weather-normalized billing determinants for the Prior Year to derive the SIR Base Rate Adjustment.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

9.8 Annual SIR Budget

In conjunction with its annual ABRAM filing each year, the Company shall provide the Department with a description of the SIR projects that it expects to complete during the current construction cycle and to include in the SIR Base Rate Adjustment for the following year. In addition, the Company will estimate the gross plant investment associated with each project. The list of projects and associated cost estimates shall be based on information available to the Company at the time it prepares the Annual SIR Budget and shall be provided for informational purposes. The specific projects undertaken during the current construction cycle and the associated cost of each project may vary due to circumstances and information that are not known by the Company at the time that the Annual SIR Budget was prepared.

9.9 Information to be Filed with the Department

On or before June 1st of each year, the Company shall file information and supporting schedules with the Department necessary for the Department to review and approve the SIR Revenue Requirements and the SIR Base Rates to be included in the ABRAM for the subsequent Rate Period. Such information shall include descriptions of all SIR Investments and the results of the calculation of the SIR Revenue Requirements Formula for the Rate Year. The Company shall also describe any factors that affected changes to the list of projects undertaken from those identified to the Department in the Company's Annual SIR Budget filed the previous year as well as any material variances in the project costs.

10.0 Information Required to be Filed with the Department

Information pertaining to all of the components of the Annual Base Rate Adjustment Mechanism is to be filed with the Department as specified in Sections 7, 8 and 9. In addition, the Company shall file revised tariff sheets reflecting the impact of applying the base rate changes provided for herein.

ANNUAL BASE RATE ADJUSTMENT MECHANISM

11.0 Currently Effective Rate Adjustment Table

	Previously Effective Rates			Currently Effective Rates				
Customer Class And Charge	Base Rate	SIR Base Rate	Base Rate w/o SIR Base Rate	PBR ADJ %	PBR Adjusted Base Rate	Energy Eff. %	SIR Base Rate	TOTAL Base Rate
	Note 1/	Note 2/	(B) – (C)	Note 3/	(1+E) * (D)	Note 4/	Note 5/	(F) x (1 + G) + (H)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
R-1								
Customer Charge	$11.60	TBD	$11.60	TBD	TBD	TBD	$0.00	$11.60
Peak 0-12 therms	0.2393	TBD	0.2393	TBD	TBD	TBD	0.0000	0.2393
Peak 12+ therms	0.1928	TBD	0.1928	TBD	TBD	TBD	0.0000	0.1928
Off-Peak 0-10 therms	0.2393	TBD	0.2393	TBD	TBD	TBD	0.0000	0.2393
Off-Peak 10+ therms	0.1928	TBD	0.1928	TBD	TBD	TBD	0.0000	0.1928
R-2								
Customer Charge	$6.25	TBD	$6.25	TBD	TBD	TBD	$0.00	$6.25
Peak	0.1158	TBD	0.1158	TBD	TBD	TBD	0.0000	0.1158
Off-Peak	0.1158	TBD	0.1158	TBD	TBD	TBD	0.0000	0.1158
R-3								
Customer Charge	$12.10	TBD	$12.10	TBD	TBD	TBD	$0.00	$12.10
Peak 0-125 therms	0.3183	TBD	0.3183	TBD	TBD	TBD	0.0000	0.3183
Peak 90+ therms	0.2224	TBD	0.2224	TBD	TBD	TBD	0.0000	0.2224
Off-Peak 0-125 therms	0.3183	TBD	0.3183	TBD	TBD	TBD	0.0000	0.3183
Off-Peak 30+ therms	0.2224	TBD	0.2224	TBD	TBD	TBD	0.0000	0.2224
R-4								
Customer Charge	$6.25	TBD	$6.25	TBD	TBD	TBD	$0.00	$6.25
Peak	0.0708	TBD	0.0708	TBD	TBD	TBD	0.0000	0.0708
Off-Peak	0.0708	TBD	0.0708	TBD	TBD	TBD	0.0000	0.0708
OL								
Per Light per Month	$2.58	TBD	$2.58	TBD	TBD	TBD	$0.00	$2.58
G-40								
Customer Charge	$19.00	TBD	$19.00	TBD	TBD	TBD	$0.00	$19.00
Peak	0.3090	TBD	0.3090	TBD	TBD	TBD	0.0000	0.3090
Off-Peak	0.3090	TBD	0.3090	TBD	TBD	TBD	0.0000	0.3090

ANNUAL BASE RATE ADJUSTMENT MECHANISM

Customer Class And Charge	Previously Effective Rates			Currently Effective Rates				
	Base Rate	SIR Base Rate	Base Rate w/o SIR Base Rate	PBR ADJ %	PBR Adjusted Base Rate	Energy Eff. %	SIR Base Rate	TOTAL Base Rate
	Note 1/	Note 2/	(B) – (C)	Note 3/	(1+E) * (D)	Note 4/	Note 5/	(F) x (1 + G) + (H)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
G-50								
Customer Charge	$19.00	TBD	$19.00	TBD	TBD	TBD	$0.00	$19.00
Peak	0.2818	TBD	0.2818	TBD	TBD	TBD	0.0000	0.2818
Off-Peak	0.2818	TBD	0.2818	TBD	TBD	TBD	0.0000	0.2818
G-41								
Customer Charge	$65.00	TBD	$65.00	TBD	TBD	TBD	$0.00	$65.00
Peak	0.1920	TBD	0.1920	TBD	TBD	TBD	0.0000	0.1920
Off-Peak	0.1216	TBD	0.1216	TBD	TBD	TBD	0.0000	0.1216
G-51								
Customer Charge	$65.00	TBD	$65.00	TBD	TBD	TBD	$0.00	$65.00
Peak	0.1774	TBD	0.1774	TBD	TBD	TBD	0.0000	0.1774
Off-Peak	0.0826	TBD	0.0826	TBD	TBD	TBD	0.0000	0.0826
G-42								
Customer Charge	$213.00	TBD	$213.00	TBD	TBD	TBD	$0.00	$213.00
Peak	0.1794	TBD	0.1794	TBD	TBD	TBD	0.0000	0.1794
Off-Peak	0.0778	TBD	0.0778	TBD	TBD	TBD	0.0000	0.0778
G-52								
Customer Charge	$213.00	TBD	$213.00	TBD	TBD	TBD	$0.00	$213.00
Peak	0.1682	TBD	0.1682	TBD	TBD	TBD	0.0000	0.1682
Off-Peak	0.0657	TBD	0.0657	TBD	TBD	TBD	0.0000	0.0657
G-43								
Customer Charge	$781.00	TBD	$781.00	TBD	TBD	TBD	$0.00	$781.00
Peak	0.0507	TBD	0.0507	TBD	TBD	TBD	0.0000	0.0507
Off-Peak	0.0193	TBD	0.0193	TBD	TBD	TBD	0.0000	0.0193
Peak Demand	2.1586	TBD	2.1586	TBD	TBD	TBD	0.0000	2.1586
Off-Peak Demand	0.6713	TBD	0.6713	TBD	TBD	TBD	0.0000	0.6713

ANNUAL BASE RATE ADJUSTMENT MECHANISM

	Previously Effective Rates			Currently Effective Rates				
Customer Class And Charge	**Base Rate**	**SIR Base Rate**	**Base Rate w/o SIR Base Rate**	**PBR ADJ %**	**PBR Adjusted Base Rate**	**Energy Eff. %**	**SIR Base Rate**	**TOTAL Base Rate**
	Note 1/	Note 2/	(B) – (C)	Note 3/	(1+E) * (D)	Note 4/	Note 5/	(F) x (1 + G) + (H)
(A)	**(B)**	**(C)**	**(D)**	**(E)**	**(F)**	**(G)**	**(H)**	**(I)**

G-53								
Customer Charge	$781.00	TBD	$781.00	TBD	TBD	TBD	$0.00	$781.00
Peak	0.0507	TBD	0.0507	TBD	TBD	TBD	0.0000	0.0507
Off-Peak	0.0193	TBD	0.0193	TBD	TBD	TBD	0.0000	0.0193
Peak Demand	2.1586	TBD	2.1586	TBD	TBD	TBD	0.0000	2.1586
Off-Peak Demand	0.6713	TBD	0.6713	TBD	TBD	TBD	0.0000	0.6713

Notes: 1/ From Column (I) of the previous year's Annual Base Rate Adjustment Filing Rate Table.
2/ From Column (H) of the previous year's Annual Base Rate Adjustment Filing .
3/ Calculated in accordance with Section 7.3 and Section 7.4.
4/ Calculated in accordance with Section 8.3.
5/ Calculated in accordance with Section 9.7.
TBD – To be determined initially in the Company's first Annual Base Adjustment Mechanism filing.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 1, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

RR-DTE-103: Please revise and submit in red-lined strikeout and clean versions the proposed cost of gas adjustment tariff, M.D.T.E. No. 63, with the following changes:

(A) At page 3 of 35 (or at page 2 of 21 in the proposed clean version), in the section entitled, Effective Date of Gas Adjustment Factor, correct the typo in spelling the word, “first”.
(B) At page 6 of 35 (or at page 4 of 21 in the proposed clean version), in the table, change, “2.184%” to “2.17%”.
(C) At page 34 of 35 (or at page 20 of 21 in the proposed clean version), add the word, “Forecast” as the first word in the definition of BD, add the word, “annual”, before the word, “gas” and replace the phrase, “the Company’s last rate case”, with, “DTE 05-27”.
(D) At page 7 of 35 (or at page 5 of 21 in the proposed clean version), in the formula for DFp, superscript X, remove the components “RFpd + WCFpd” from the denominator and place into separate additive components.
(E) At page 6 of 35 (or at page 4 of 21 in the proposed clean version), eliminate the subscript, “p” from the component BDF, at the third line in the paragraph entitled, Peak GAF Formula.
(F) At page 6 of 35 (or at page 4 of 21 in the proposed clean version), in the sentence before the table, add the following phrase, “as approved in DTE 05-27”. Eliminate any notation of standby sales service, SBD, as shown on page 7 of 35 (or at page 5 of 21 in the proposed clean version), and used within the formula for Dp, superscript X.

Response: Please see the attached revised proposed Cost of Gas Adjustment Clause, M.D.T.E. No. 36, tariff with the requested revisions, both in a clean (Attachment RR-DTE-103 (Clean)) and red-lined strikeout (Attachment RR-DTE-103 (Redline)) version.

COST OF GAS ADJUSTMENT CLAUSE

Section

1.0 Purpose

The purpose of this clause is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company"), subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on a semiannual basis, its rates for firm gas sales service in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchase gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit all supplier refunds and the margins above the Annual Threshold associated with capacity credits from non-core sales and transportation, interruptible sales and transportation and capacity release sales to firm ratepayers.

2.0 Applicability

This Cost of Gas Adjustment ("CGAC") shall be applicable to Bay State and all firm gas sales made by Bay State, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the Department. See Section 13.0, "Other Rules."

COST OF GAS ADJUSTMENT CLAUSE

3.0 Cost of Firm Gas Allowable for CGAC

All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the CGAC. Any costs recovered through application of the CGAC shall be identified and explained fully in the semi-annual filings outlined in Section 12.0.

4.0 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

5.0 Definitions

The following terms shall be defined in this section, unless the context requires otherwise.

(1) **Annual Threshhold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.

(2) **Bad Debt Expense** - is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.

(3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.

(4) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.

(5) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal*.

(6) **Economic Benefit** - The difference between the revenues received and the marginal cost determined to serve non-core customers.

(7) **Interruptible Sales Margins** - The economic benefit derived from the interruptible sale of gas downstream of the Company's distribution system.

COST OF GAS ADJUSTMENT CLAUSE

(8) **Inventory Finance Charges** - As incurred or billed each month for the carrying costs on the value of the balance of inventory gas for the respective month. The total charges shall represent an accumulation of the projected monthly charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate of the Company or through a trust or other financing vehicle.

(9) **Local Production Capacity and Storage Costs** - Include the ancillary supply costs of providing local manufactured gas, gas dispatching, gas acquisition, and miscellaneous A&G costs as determined in the Company's most recent rate proceeding. Per this proceeding, $7,401,961 shall be allocated to the peak period and $325,300 shall be allocated to the off-peak period.

(10) **SMBA** – Simplified Market Based Allocation Method - Used in determining the allocation of gas costs among High and Low Load Factor classes.

(11) **Non-Core Commodity Costs** - The commodity cost of gas assigned to non-core sales to which the GAF is not applied. Non-core sales include sales made under interruptible contracts, non-core contracts and off-system sales.

(12) **Non-Core Sales Margins** - The economic benefit derived from non-core transactions to which the GAF is not applied, including interruptible sales and other non-core sales generated from the use of the Company's Gas Supply resource portfolio.

(13) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

(14) **Number of Days Lag** - The number of days lag to calculate the purchased gas working capital requirement as approved by the Department.

(15) **Off-Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the off-peak season.

(16) **Off-Peak Demand** - Unless otherwise approved by the Department, the gas supply demand and transmission capacity assigned by the Company to serve firm load in the off-peak season.

(17) **Off-Peak Period** - May through October.

(18) **Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the peak season.

(19) **Peak Demand** - Unless otherwise approved by the Department, gas supply demand, peaking demands, storage and transmission capacity assigned by the Company to service firm load in the peak season.

(20) **Peak Period** - November through April.

(21) **PR Allocator** - The percentage allocated for the portion of annual capacity charges assigned to the seasons calculated in each CGA filing.

(22) **Pretax Weighted Cost of Capital** - The result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one, minus the currently effective combined tax rate, plus the weighted cost of debt.

COST OF GAS ADJUSTMENT CLAUSE

(23) **Purchased Gas Working Capital** - The allowable working capital derived from peak and off-peak, demand and commodity related costs.

(24) **Tax Rate** is the combined State and Federal income tax rate.

(25) **Weighted Cost of Capital** is the weighted cost of capital as set in the Company's most recent base rate case.

(26) **Weighted Cost of Debt** is the weighted cost of debt as set in the Company's most recent base rate case.

6.0 Gas Adjustment Factor (GAF) Formula

The Gas Adjustment Factor (GAF) Formula shall be computed on a semiannual basis using forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

A separate seasonal GAF will be computed for the combined Low Load Factor classes namely Rates R-3, R-4, G-40, G-41, G-42 and G-43; and for the combined High Load Factor classes namely Rates R-1, R-2, OL, G-50, G-51, G-52 and G-53. The calculation of each seasonal GAF utilizes information periodically established by the DTE. The table below lists the following approved cost factors as approved in D.T.E. 05-27:

Local Production & Storage Cost	$7,727,261
LNG/LPG Production Cost included above	$5,258,855
Bad Debt Expense Percentage	2.17%

Peak GAF Formula

The Peak GAF shall be comprised of a peak demand factor (DFp), a peak commodity factor (CFp), a peak production and storage demand factor (PSp), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF) defined in Section 15.00, for the Company's High and Low Load Factor classes and calculated at the beginning of the peak season according to the following formula:

$$GAFp^{x} = DFp^{x + PSpx} + CFp^{x} + BDF - R1 - R2$$

COST OF GAS ADJUSTMENT CLAUSE

Peak Demand Factor (DFp) Formula

$$DFp^x = \frac{Dp^x - NCSMp^x - STRANDp^x}{P : Sales^x} + RFpd + WCFpd$$

and:

$Dp^x = BASEDp^x + REMAINDp^x + PSp^x$

and:

$NCSMp^x = CRR^x + ISM^x + NTSM^x$

and:

RFpd = Rpd/P:Sales

and:

$$WCFpd = \frac{\left[\dfrac{(WCApd \times CC) - (WCApd \times CD)}{(1 - TR)}\right] + (WCApd \times CD) + WCRpd}{P : Sales}$$

and:

WCApd = Dp x (DL/365)

Where:

BASEDp	Peak period base use demand charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August's daily loads.
CC	Weighted cost of capital as defined in Section 500.
CD	Weighted cost of debt as defined in Section 5.00.
CRR	The returnable Capacity Release Revenues allocated to the peak period. See Section 7.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dp	Demand Charges allocated to the peak period as defined in Section

COST OF GAS ADJUSTMENT CLAUSE

	5.00.
$NCSMp^x$	The sum of the returnable Interruptible Non-Core Sales Margins, the returnable Capacity Release Revenues and the Off-System margins.
ISM	The returnable Interruptible Sales Margins allocated to the peak period. See Section 7.00.
NTSM	The returnable Off-System Sales Margins allocated to the peak period. See Section 7.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINDp	Peak period remaining use demand charges assigned to classes on the basis of their load's contribution to the design day load less their base use entitlements to pipeline supplies. This remaining capacity cost is allocated to seasons using the Proportional Responsibility (PR) allocator.
RFpd	Peak demand charge reconciliation adjustment factor per billed peak sales volume associated with demand charges related to the peak period.
Rpd	Reconciliation Costs - Peak demand deferred gas costs, Account 175.21 balance, inclusive of the associated Account 175.21 interest, as outlined in Section 9.00.
STRANDp	Stranded production and Storage costs assigned to the peak period and classes in the same manner as remaining use demand charges.
TR	Combined Tax Rate as defined in Section 5.00
WCApd	Demand charges allowable for working capital application as defined in Section 10.00.
WCFpd	Working Capital allowable factor per billed peak sales volume associated with demand charges allocated to the peak period as defined in Section 10.00.
WCRpd	Working Capital reconciliation adjustment associated with peak demand charges - Account 176.24 balance as outlined in Section 10.00.
x	Designates Load Factor Specific allocation of costs, based on Simplified Market Based Allocation factors as determined in the Company's most recent rate proceeding.
PSpx	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Peak Commodity Factor (CFp) Formula

$$CFp^x = \left[\frac{Cp^x - NCCCp^x + FC^x}{P : Sales^x} \right] + RFpc + WCFpc$$

and:

$$Cp^x = BASECp^x + REMAINCpx - SBCp^x$$

and:

$$RFpc = Rpc / P{:}Sales$$

COST OF GAS ADJUSTMENT CLAUSE

and:

$$WCFpc = \frac{\left[\frac{(WCApc \times CC) - (WCApc \times CD)}{(1 - TR)}\right] + (WCApc \times CD) + WCRpc}{P{:}\ Sales}$$

and:

$$WCApc = Cp \times (DL/365)$$

Where:

BASECp	Peak period base use commodity charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August daily loads.
CC	Weighted costs of capital as defined in Section 5.00
CD	Weighted costs of debt as defined in Section 5.00.
Cp	Commodity Charges allocated to the peak period as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
FC	Inventory finance charges as defined in Section 5.00.
NCCCp	Non-Core Commodity Costs allocated to the peak period as defined in Section 5.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINCp	Peak period remaining use commodity charges computed as dispatched commodity costs less base use commodity costs.
RFpc	Peak commodity charge reconciliation adjustment factor per billed peak sales volume associated with commodity charges related to the peak period.
Rpc	Reconciliation Adjustment Costs - Account 175.23 balance, inclusive of the associated Account 175.23 interest, as outlined in Section 9.00.
TR	Combined Tax rate as defined in Section 5.00.
WCApc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFpc	Working Capital allowable factor per peak sales volume associated with commodity charges allocated to the peak period as defined in Section 10.00.
WCRpc	Working Capital reconciliation adjustment associated with peak commodity charges Account 175.24 balance as outlined in Section 10.00.
x	Designates Load Factor class specific allocation of costs, based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.

COST OF GAS ADJUSTMENT CLAUSE

Off-Peak GAF Formula

The Off-Peak GAF shall be comprised of an off-peak demand factor (Dfop) an off-peak production and storage demand factor (PSop), an off-peak commodity factor (Cfop), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF), defined in Section 16.00 for the Company's High and Low Load Factor classes, and calculated at the beginning of the off-peak season according to the following formula.

$GAFop^{X} = DFop^{X} + CFop^{X} + PSopx + BDF - R1 \text{ and } R2$

Off-Peak Demand Factor (DFop) Formula

$$DFop^{x} = \frac{Dop^{x}}{OP{:}Sales^{x}} + RFopd + WCFopd$$

and:

$Dop^{X} = Sum{:}BLDop^{X} + (Sum{:}BLDXop^{X} \text{ x } (1 - PR))$

and:

$RFopd = Ropd / OP{:}Sales$

and:

$$WCFopd = \frac{\frac{[(WCAopd \text{ x } CC) - (WCAopd \text{ x } CD)]}{(1 - TR)} + (WCAopd \text{ x } CD) + WCRopd}{(OP{:}Sales)}$$

and:

$WCAopd = Dop \ (DL/365)$

Where:

BLDop Demand charges billed to the Company during the off peak period for the portion of base demand associated with serving base load requirements as defined in Section 5.00.

BLDXop Base demand costs in excess of demand costs associated with base load level billed to the

COST OF GAS ADJUSTMENT CLAUSE

	Company during the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dop	Demand charges allocated to the off-peak period as defined in Section 5.00.
LBop	Portion of Upstream Pipeline Reservation Charges assigned to Load Balancing.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
PR	Proportional Responsibility Allocator - A percentage representing a portion of capacity/product charges incurred in the off-peak season and assigned to the peak period calculated in each CGA filing as defined in Section 5.0.
RFopd	Off-peak demand charge reconciliation adjustment factor per billed off peak throughput volume associated with demand charges related to the off peak period.
Ropd	Reconciliation Costs - Account 175.11 balance, inclusive of the associated Account 175.11 interest, as outlined in Section 9.00.
SMBA	Simplified Market Based Allocator – Load Factor specific allocator as defined in Section 5.00
TR	Combined Tax rate as defined in Section 5.0
WCAopd	Demand charges allowable for working capital application as defined in Section 6.1.
WCFopd	Working Capital factor allowable per billed off-peak sales associated with demand charges allocated to the off-peak period as defined in Section 10.0
WCRopd	Working Capital reconciliation adjustment associated with off-peak demand charges balance account 175.14 balance as outlined in Section 10.0.
x	Designates Load Factor specific allocation of costs based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.
PS_{op}^{x}	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to off-peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Off-Peak Commodity Factor (CFop) Formula

$$CFop^{x} = \frac{Cop^{x} - NCCCop^{x}}{OP : Sales^{x}} + RFopc + WCFopc$$

COST OF GAS ADJUSTMENT CLAUSE

and:

$Cop^{X} = Sum{:}OPC^{X} - BOao^{X} - INJop^{X} - LIQop^{X}$

and:

$BOao^{X} = [(BOop - (BOvol \; x \; (TPop/TPvolop))) \; MBA^{X}]$

and:

RFopc = Ropc/OP:Sales

and:

$$WCFopc = \frac{\dfrac{[(WCAopc \times CC)-(WCAopc \times CD)]}{(1 - TR)} + (WCAopc \times CD) + WCRopc}{OP : Sales}$$

and:

WCAopc = Cop (DL/365)

Where:

BOao	LNG Boil-off allocation as defined in Section 9.00.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
Cop	Commodity Charges billed to the off-peak period as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers. See Section 10.00.
INJop	Injections into underground storage during the off-peak period.
LIQop	Liquefactions into storage during the off-peak period.
NCCCop	Non-core commodity costs allocated to the off-peak period as defined in Section 6.05.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
OPC	Commodity charges associated with gas supply sent out in the off-peak season as defined in Section 5.00.
RFopc	Off peak commodity charge reconciliation adjustment factor per billed off peak sales volume associated with commodity charges related to the off-peak period.
Ropc	Reconciliation Adjustment Cost - Account 175.13 balance, inclusive of the associated

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	Account 175.13 interest, as outlined in Section 9.00.
TPop	Total pipeline commodity purchase charges for the off-peak period.
TPvolop	Total pipeline purchase volumes for the off-peak period.
TR	Combined Tax rate as defined in Section 5.00.
WCAopc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFopc	Working Capital allowable per off-peak sales volume associated with commodity charges allocated to the off-peak period as defined in Section 10.00.
WCRopc	Working Capital reconciliation adjustment associated with off-peak commodity charges - Account 176.14 balance, as outlined in Section 10.00.
x	Designates Load Factor specific allocation of costs, based on Simplified Market Based Allocation factors.

7.0 Interruptible Sales, Off-System Sales and Capacity Release Revenues

A threshold level of margins will be established annually and separately for Interruptible Sales, Off-System Sales and Capacity Release Revenues. Any margins earned in excess of the predetermined level shall be divided between the Company and its firm sales customers under a 25/75 sharing arrangement. The threshold level of margins shall be adjusted to reflect additions or losses from Customers who switch from FT, FS or Interruptible Transportation ("IT") to IS and conversely, from IS to FT, FS or IT. The Company shall adjust the threshold level annually to reflect Interruptible Sales, Off-System sales, and capacity release revenues for the twelve-month period ending April 30 of each year.

Margins from Interruptible Sales, Off-System Sales and Capacity Release will be reflected as separate credits in the peak season GAF and shall be calculated as the sum of the following:

(1) 100% of the margins earned up to the predetermined threshold level.
(2) 75% of the margins earned in excess of the predetermined threshold level.

8.0 Gas Suppliers' Refunds - Accounts 265.85 and 265.86

Refunds from upstream capacity suppliers and suppliers of gas are credited to Account 265.85, "Refund-November" if received during the months of March through August, and to Account 265.86 "Refund-May", if received during the months of September through February.

A refund program shall be initiated with each semiannual GAF filing and shall remain in effect for a period of one year. The balance in Account 265.85 shall be placed into a refund program with each November filing. The balance in Account 265.86 shall be placed into a refund program

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with each May filing. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. The Company shall track and report on all Account 265.85 and Account 265.86 activities. If during any twelve-month period commencing with the billing month of November for Account 265.85 and May for Account 265.86, the projected supplier refund factor is less than one-hundredth of a cent per therm ($0.0001), the respective supplier refund account balance shall be transferred into Account 175.26 or Account 175.16 for the November and May filings respectively.

<u>Gas Supplier's Refund Factors</u>

R1 The per unit supplier refund associated with the Refund – May program. The following formula shall be used to calculate the R1 factor.

$$R1 = \frac{R1\$ + I}{A:Sales}$$

Where:

R1$	Ending balance in Account 265.86 "Refund – May"
I	Total forecasted interest calculated on the R1$ balance computed at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

R2 The per unit supplier refund associated with the Refund – November program. The following formula shall be used to calculate the R2 factor.

$$R2 = \frac{R2\$ + I}{A:Sales}$$

Where:

R2$	Ending balance in Account 265.85 "Refund – November"
I	Total forecasted interest calculated on the R2$ balance computed at the Federal Reserve Prime Rate based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

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9.0 <u>Reconciliation Adjustments</u> <u>– Other than Working Capital</u>

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Capacity Costs Allowable per Peak Demand Formula shall be:

i. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the peak season.

ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.

iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Charges associated with peaking, production and storage capacity to serve firm load in the peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service.

v. Credits associated with Non-Core Sales Margins or economic benefits from capacity release, off-system sales for resale and interruptible sales margins allocated to the firm sales service.

vi. Credits associated with daily imbalance charges billed transportation customers in the peak period.

vii. Peak demand Carrying Charges as defined in Section 5.00.

(b) Gas Costs Allowable Per Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefaction into storage.

ii. Credit non-core commodity costs assigned to non-core customers to which the CGAC does not apply, as defined in Section 6.06 (NCCCp).

iii. Inventory finance charges (FC).

iv. Peak commodity Carrying Charges as defined in Section 5.00.

(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity and product demand procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with transmission capacity and product demand

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procured by the Company to serve firm load in excess of base load requirements in the off-peak period

iii. Credits associated with daily imbalance charges billed transportation customers in the off peak period.

iv. Off-peak demand Carrying Charges as defined in Section 5.00.

v. Other A & G and Acct. 851 charges associated with peaking production and storage capacity to serve firm load in the off-peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service

(d) Gas Costs Allowable Per Off-Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Credits associated with Non-core commodity costs from non-core sales to which the GAF is not applied, as defined in Section 5.00.

iii. Off-peak commodity Carrying Charges as defined in Section 5.00.

(2) Calculation of the Reconciliation Adjustments

Account 175 contains the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Peak Demand (Account 175.21), Peak Production and Storage Demand (175.22) ,Peak Commodity (Account 175.23), Off-Peak Demand (Account 175.11), Off-Peak Production and Storage Demand (175.12) and Off-Peak Commodity (Account 175.13). Account 175.21 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Peak Demand Factor for the High and Low Load Factor classes, (DFp^X) times monthly firm sales volumes forHigh and Low Load Factor classes, and the total capacity costs allowable per the peak demand formula. Account 175.22 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Peak Commodity Factor for the High and Low Load Factorclasses, (CFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total commodity costs allowable per the peak commodity formula. Account 175.22 shall contain the accumulated difference between revenues as calculated by multiplying the Peak Production and Storage Demand Factor for the High and Low Load Factor class, (PS_p^x) times monthly firm sales volumes forthe High and Low Load Factor classes, and the total production and storage costs allowable per the peak production and storage demand formula. Account 175.11 shall contain the accumulated difference between revenues toward capacity costs

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calculated by multiplying the Off-Peak Demand Factor for the High and Low Load Factor classes, ($DFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total capacity costs allowable per the off-peak demand formula. Account 175.13 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Off-Peak Commodity Factor for the High and Low Load Factor classes, ($CFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total commodity costs allowable per the off-peak commodity formula. Account 175.12 shall contain the accumulated difference between revenues as calculated by multiplying the Off-Peak Production and Storage Demand Factor for the High and Low Load Factor classes, (PS_{op}^x) times monthly firm sales volumes for the High and Low Load Factorclasses, and the total production and storage costs allowable per the off-peak production and storage demand formula.

Carrying Charges as defined in Section 5.00 shall be added to each end-of-the-month balance. The peak demand reconciliation adjustment factor (RFpd) shall be determined for use in the peak GAF calculation by dividing the peak demand account (175.21) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak production & storage demand reconciliation adjustment factor (RFppsd) shall be determined for use in the peak GAF calculation by dividing the peak production and storage demand account (175.22) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak commodity reconciliation adjustment factor (RFpc) shall be determined for use in the peak GAF calculation by dividing the peak commodity account (175.23) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The off-peak demand reconciliation adjustment factor (RFopd) shall be determined for use in the off peak GAF calculation by dividing the off-peak demand account (175.11) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak production and storage demand reconciliation adjustment factor (RFoppsd) shall be determined for use in the off-peak GAF calculation by dividing the off-peak production and storage demand account (175.12) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak commodity reconciliation adjustment factor (RFopc) shall be determined for use in the off-peak GAF calculation by dividing the off-peak commodity account (175.13) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period.

The peak period reconciliation will be filed thirty (30) days prior to the peak period GAF filing, which is seventy-five (75) days prior to the effective date.

The off-peak period reconciliation shall be filed thirty (30) days prior to the off-peak period GAF filing, which is seventy-five (75) days prior to the effective date.

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10.0 <u>Working Capital Reconciliation Adjustments</u>

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Working Capital Gas Costs Allowable Per Peak Demand Formula shall be:

i. Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the peak season.

ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.

iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Carrying Charges

(b) Working Capital Gas Costs Allowable Per Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average costs of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-Core Commodity Costs associated with non-core sales to which the GAF is not applied.

iii. Carrying charges.

(c) Working Capital Gas Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the off-peak period.

iii. Carrying charges.

(d) Working Capital Gas Costs Allowable Per Off-Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, procured by the company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes

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purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-core commodity costs associated with non-core sales to which the GAF is not applied, as defined in section 6.05.

iii. Carrying charges.

(2) The peak and off-peak, demand, and commodity working capital requirements shall be calculated by applying the Company's days lag divided by 365 days to the working capital costs allowable per each formula.

(3) The peak and off-peak, demand, and commodity working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working capital requirement to calculate the respective returns on working capital. The interest portion of each working capital allowance is calculated by multiplying each working capital requirement by the weighted cost of debt. This portion is tax deductible. The return on each working capital less the interest portion of each working capital is then divided by one minus the tax rate. This figure plus the interest calculated above equals the working capital allowance for each.

(4) Calculation of the Reconciliation Adjustments

Accounts 175.14, 175.13, 175.24, and 175.23 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company plus Carrying Charges as defined in Section 5.00.

The components of the Company's purchased gas days lag shall be recalculated each season based upon actual CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenues. Each Account 175 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

The peak demand working capital reconciliation adjustment shall be determined for use in the peak demand factor calculations incorporating the peak demand working capital account 175.14 balance as of the peak reconciliation date designated by the Company. A peak commodity working capital reconciliation adjustment shall be determined for use in the peak commodity factor calculations incorporating the peak commodity working capital account 175.13 balance as of the peak reconciliation date designated by the Company. An off-peak working

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capital reconciliation adjustment (WCRopd) shall be determined for use in the off -peak demand factor calculations incorporating the off-peak demand working capital account (175.24) balance as of the off-peak reconciliation date designated by the Company. An off-peak commodity working capital reconciliation adjustment (WCRopc) shall be determined for use in the off-peak commodity working capital account (175.23) balance as of the off-peak reconciliation date designated by the Company.

11.0 <u>Application of GAF to Bills</u>

The Company will employ the GAFs as follows: The peak season rates to each Load Factor class shall be calculated by adding the respective peak demand factor and the peak commodity factor. The off-peak season rates to each Load Factor class shall be calculated by adding the respective off-peak demand factor and the off-peak commodity factor. The GAFs ($/therm) for each Load Factor class for each season shall be calculated to the nearest one-hundredth of a cent per therm ($0.0001) and will be applied to each customer's monthly sales volume within the corresponding Load Factor class.

12.0 <u>Information Required to be Filed with the Department</u>

Information pertaining to the cost of gas adjustment shall be filed with the Department in accordance with the Company's standardized forms approved by the Department. Required filings include a semiannual GAF filing which shall be submitted to the Department at least 45 days before the date on which a new GAF is to be effective.

Additionally the Company shall file with the Department a complete list of all gas costs claimed as recoverable through the CGAC over the previous season, as included in the seasonal reconciliation. This information shall be submitted with each seasonal GAF filing, along with complete documentation of the reconciliation adjustment calculations.

13.0 <u>Other Rules</u>

(1) The Department may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

(2) The Company may, at any time, file with the Department an amended GAF. An amended GAF filing must be submitted 10 days before the first billing cycle of the month

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in which it is proposed to take effect.

(3) The Department may, at any time, require the Company to file an amended GAF.

(4) The operation of the cost of gas adjustment clause is subject to all powers of suspension and investigation vested in the Department by G.L. c.164.

14.0 Customer Notification

The Company will design a notice, which explains in simple terms to customers the GAF, the nature of any change in the GAF and the manner in which the GAF is applied to the bill. The Company will submit this notice for approval at the time of each GAF filing.

Upon approval by the Department, the Company must immediately distribute these notices to all of its customers either through direct mail or with its bills.

15.0 Bad Debt Allowance

15.01 Purpose

The purpose of this provision is to establish a procedure that, subject to the jurisdiction of the Department, allows Bay State to adjust, on a semi-annual basis, its rates for the recovery of Bad Debt Expense

15.02 Bad Debt (BDF) Formula

The Bad Debt (BDF) Formula shall be computed on an annual basis using forecasts of bad debt expense associated with gas costs, gas costs, carrying charges, sales volumes, and a working capital allowance. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing. The forecast of bad debt expense associated with gas costs shall be based on the Company’s projected gas costs in the respective seasonal GAF filings and the percent of net write-offs to total firm revenues as determined in the Company’s last rate proceeding.

The calculation at the beginning of the off-peak season shall be on a projected annual basis. The calculation at the beginning of the peak season will update the remaining months of the projected annual period with actual bad debt expenses and collections for the available months and projections for the remaining months of the annual period. The following formula shall be used to calculate the Bad Debt factor.

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$$BDF = \frac{BD + RAbd + WCbd + I}{A{:}Sales}$$

and:

$$WCbd = \frac{(WCAbd * CC) - (WCAbd * CD)}{(1 - TR)} + (WCAbd * CD)$$

and:

$$WCAbd = BD * (DL/365)$$

Where:

A:Sales Forecast annual sales volumes.

BD Forecast Bad Debt Expense as defined in Section 5.00; derived by multiplying the forecast annual gas costs by the percent of annual net write-offs to annual firm revenues as determined in D.T.E. 05-27.

CC Weighted cost of capital as defined in Section 5.00.

CD Weighted cost of debt as defined in Section 5.00.

DL Number of days lag from the purchase of gas from suppliers to the payment by customers.

I Interest on total bad debt allowance plus working capital on bad debt calculated at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.

RAbd Bad Debt Expense reconciliation adjustment - Account 175.31 balance.

TR Combined Tax rate as defined in Section 5.00.

WCAbd Bad Debt allowable for working capital application defined as the costs associated with the gas cost portion of bad debt incurred by the Company to serve firm load.

WCbd Working Capital Allowance associated with the gas portion of bad debt for the period including the Pretax Weighted Cost of Capital as defined in Section 5.00.

15.03 Bad Debt Reconciliation Adjustment

Account 175.31 shall contain the accumulated difference between the annual revenues toward bad debt, as calculated by multiplying the bad debt factors (BDF) times monthly firm sales volumes, and the annual allowed Bad Debt expenses, allowed working capital on Bad Debt and Carrying Charges as defined in Section 5.00.

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An annual bad debt reconciliation adjustment (RAbd - as defined in Section 15.02) shall be determined for use in the bad debt factor calculations incorporating the bad debt working capital account (175.32) balance as of the reconciliation date designated by the Company.

(a) Costs Allowable per Bad Debt Formula shall be:

i. Un-collectable gas costs incurred by the Company to serve firm sales load, as determined by deriving the portion of actual net write-offs associated with gas cost collections.

ii. Account 175.32 – Bad Debt, Carrying Charges.

iii. Working Capital Gas Costs Allowable per Bad Debt Formula, which shall be charges associated with bad debt incurred by the Company to serve firm sales load and applied to the working capital formula.

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1.0 Purpose

The purpose of this clause is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company"), subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on a semiannual basis, its rates for firm gas sales service in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchase gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit all supplier refunds and the margins above the Annual Threshold associated with capacity credits from non-core sales and transportation, interruptible sales and transportation and capacity release sales to firm ratepayers.

2.0 Applicability

This Cost of Gas Adjustment ("CGAC") shall be applicable to Bay State and all firm gas sales made by Bay State, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the Department. See Section 13.0, "Other Rules."

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3.0 Cost of Firm Gas Allowable for CGAC

All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the CGAC. Any costs recovered through application of the CGAC shall be identified and explained fully in the semi-annual filings outlined in Section 12.0.

4.0 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

5.0 Definitions

The following terms shall be defined in this section, unless the context requires otherwise.

(1) **Annual Threshhold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.
(2) **Bad Debt Expense** - is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.
(3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.
(4) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.
(5) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal*.
(6) **Economic Benefit** - The difference between the revenues received and the marginal cost determined to serve non-core customers.
(7) **Interruptible Sales Margins** - The economic benefit derived from the interruptible sale of gas downstream of the Company's distribution system.

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(8) **Inventory Finance Charges** - As incurred or billed each month for the carrying costs on the value of the balance of inventory gas for the respective month. The total charges shall represent an accumulation of the projected monthly charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate of the Company or through a trust or other financing vehicle.

(9) **Local Production Capacity and Storage Costs** - Include the ancillary supply costs of providing local manufactured gas, gas dispatching, gas acquisition, and miscellaneous A&G costs as determined in the Company's most recent rate proceeding. Per this proceeding, $7,401,961 shall be allocated to the peak period and $325,300 shall be allocated to the off-peak period.

(10) **SMBA** – Simplified Market Based Allocation Method - Used in determining the allocation of gas costs among High and Low Load Factor classes.

(11) **Non-Core Commodity Costs** - The commodity cost of gas assigned to non-core sales to which the GAF is not applied. Non-core sales include sales made under interruptible contracts, non-core contracts and off-system sales.

(12) **Non-Core Sales Margins** - The economic benefit derived from non-core transactions to which the GAF is not applied, including interruptible sales and other non-core sales generated from the use of the Company's Gas Supply resource portfolio.

(13) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

(14) **Number of Days Lag** - The number of days lag to calculate the purchased gas working capital requirement as approved by the Department.

(15) **Off-Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the off-peak season.

(16) **Off-Peak Demand** - Unless otherwise approved by the Department, the gas supply demand and transmission capacity assigned by the Company to serve firm load in the off-peak season.

(17) **Off-Peak Period** - May through October.

(18) **Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the peak season.

(19) **Peak Demand** - Unless otherwise approved by the Department, gas supply demand, peaking demands, storage and transmission capacity assigned by the Company to service firm load in the peak season.

(20) **Peak Period** - November through April.

(21) **PR Allocator** - The percentage allocated for the portion of annual capacity charges assigned to the seasons calculated in each CGA filing.

(22) **Pretax Weighted Cost of Capital** - The result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one, minus the currently effective combined tax rate, plus the weighted cost of debt.

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(23) **Purchased Gas Working Capital** - The allowable working capital derived from peak and off-peak, demand and commodity related costs.

(24) **Tax Rate** is the combined State and Federal income tax rate.

(25) **Weighted Cost of Capital** is the weighted cost of capital as set in the Company's most recent base rate case.

(26) **Weighted Cost of Debt** is the weighted cost of debt as set in the Company's most recent base rate case.

6.0 Gas Adjustment Factor (GAF) Formula

The Gas Adjustment Factor (GAF) Formula shall be computed on a semiannual basis using forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

A separate seasonal GAF will be computed for the combined Low Load Factor classes namely Rates R-3, R-4, G-40, G-41, G-42 and G-43; and for the combined High Load Factor classes namely Rates R-1, R-2, OL, G-50, G-51, G-52 and G-53. The calculation of each seasonal GAF utilizes information periodically established by the DTE. The table below lists the following approved cost factors as approved in D.T.E. 05-27:

Local Production & Storage Cost	$7,727,261
LNG/LPG Production Cost included above	$5,258,855
Bad Debt Expense Percentage	2.17~~8~~4%

Peak GAF Formula

The Peak GAF shall be comprised of a peak demand factor (DFp), a peak commodity factor (CFp), a peak production and storage demand factor (PSp), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF~~p~~) defined in Section 15.00, for the Company's High and Low Load Factor classes and calculated at the beginning of the peak season according to the following formula:

$$GAFp^{x} = DFp^{x + PSpx} + CFp^{x} + BDF - R1 - R2$$

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Peak Demand Factor (DFp) Formula

$$DFp^x = \frac{Dp^x - NCSMp^x - STRANDp^x}{P : Sales^x} + RFpd + WCFpd$$

and:

$$Dp^x = BASEDp^x + REMAINDp^x + PSp^x \cancel{- SBDp^x}$$

and:

$$NCSMp^x = CRR^x + ISM^x + NTSM^x$$

and:

$$RFpd = Rpd/P{:}Sales$$

and:

$$WCFpd = \frac{\left[\frac{(WCApd \times CC) - (WCApd \times CD)}{(1 - TR)}\right] + (WCApd \times CD) + WCRpd}{P : Sales}$$

and:

$$WCApd = Dp \times (DL/365)$$

Where:

BASEDp	Peak period base use demand charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August's daily loads.
CC	Weighted cost of capital as defined in Section 500.
CD	Weighted cost of debt as defined in Section 5.00.
CRR	The returnable Capacity Release Revenues allocated to the peak period. See Section 7.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dp	Demand Charges allocated to the peak period as defined in Section

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	5.00.
$NCSMp^X$	The sum of the returnable Interruptible Non-Core Sales Margins, the returnable Capacity Release Revenues and the Off-System margins.
ISM	The returnable Interruptible Sales Margins allocated to the peak period. See Section 7.00.
NTSM	The returnable Off-System Sales Margins allocated to the peak period. See Section 7.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINDp	Peak period remaining use demand charges assigned to classes on the basis of their load's contribution to the design day load less their base use entitlements to pipeline supplies. This remaining capacity cost is allocated to seasons using the Proportional Responsibility (PR) allocator.
RFpd	Peak demand charge reconciliation adjustment factor per billed peak sales volume associated with demand charges related to the peak period.
Rpd	Reconciliation Costs - Peak demand deferred gas costs, Account 175.21 balance, inclusive of the associated Account 175.21 interest, as outlined in Section 9.00.
STRANDp	Stranded production and Storage costs assigned to the peak period and classes in the same manner as remaining use demand charges.
TR	Combined Tax Rate as defined in Section 5.00
WCApd	Demand charges allowable for working capital application as defined in Section 10.00.
WCFpd	Working Capital allowable factor per billed peak sales volume associated with demand charges allocated to the peak period as defined in Section 10.00.
WCRpd	Working Capital reconciliation adjustment associated with peak demand charges - Account 176.24 balance as outlined in Section 10.00.
x	Designates Load Factor Specific allocation of costs, based on Simplified Market Based Allocation factors as determined in the Company's most recent rate proceeding.
PSpx	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

<u>Peak Commodity Factor (CFp) Formula</u>

$$CFp^x = \left[\frac{Cp^x - NCCCp^x + FC^x}{P : Sales^x} \right] + RFpc + WCFpc$$

and:

$$Cp^x = BASECp^x + REMAINCpx - SBCp^x$$

and:

$$RFpc = Rpc / P{:}Sales$$

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and:

$$WCFpc = \frac{\left[\frac{(WCApc \times CC) - (WCApc \times CD)}{(1 - TR)}\right] + (WCApc \times CD) + WCRpc}{P{:}\ Sales}$$

and:

WCApc = Cp x (DL/365)

Where:

BASECp	Peak period base use commodity charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August daily loads.
CC	Weighted costs of capital as defined in Section 5.00
CD	Weighted costs of debt as defined in Section 5.00.
Cp	Commodity Charges allocated to the peak period as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
FC	Inventory finance charges as defined in Section 5.00.
NCCCp	Non-Core Commodity Costs allocated to the peak period as defined in Section 5.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINCp	Peak period remaining use commodity charges computed as dispatched commodity costs less base use commodity costs.
RFpc	Peak commodity charge reconciliation adjustment factor per billed peak sales volume associated with commodity charges related to the peak period.
Rpc	Reconciliation Adjustment Costs - Account 175.23 balance, inclusive of the associated Account 175.23 interest, as outlined in Section 9.00.
TR	Combined Tax rate as defined in Section 5.00.
WCApc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFpc	Working Capital allowable factor per peak sales volume associated with commodity charges allocated to the peak period as defined in Section 10.00.
WCRpc	Working Capital reconciliation adjustment associated with peak commodity charges Account 175.24 balance as outlined in Section 10.00.
x	Designates Load Factor class specific allocation of costs, based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.

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Off-Peak GAF Formula

The Off-Peak GAF shall be comprised of an off-peak demand factor (Dfop) an off-peak production and storage demand factor (PSop), an off-peak commodity factor (Cfop), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF), defined in Section 16.00 for the Company's High and Low Load Factor classes, and calculated at the beginning of the off-peak season according to the following formula.

$$GAFop^{X} = DFop^{X} + CFop^{X} + PSopx + BDF - R1 \text{ and } R2$$

Off-Peak Demand Factor (DFop) Formula

$$DFop^{x} = \frac{Dop^{x}}{OP{:}Sales^{x}} + RFopd + WCFopd$$

and:

$$Dop^{X} = Sum{:}BLDop^{X} + (Sum{:}BLDXop^{X} \times (1 - PR))$$

and:

$$RFopd = Ropd / OP{:}Sales$$

and:

$$WCFopd = \frac{\dfrac{[(WCAopd \times CC) - (WCAopd \times CD)]}{(1 - TR)} + (WCAopd \times CD) + WCRopd}{(OP{:}Sales)}$$

and:

$$WCAopd = Dop\ (DL/365)$$

Where:

BLDop — Demand charges billed to the Company during the off peak period for the portion of base demand associated with serving base load requirements as defined in Section 5.00.

BLDXop — Base demand costs in excess of demand costs associated with base load level billed to the

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	Company during the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dop	Demand charges allocated to the off-peak period as defined in Section 5.00.
LBop	Portion of Upstream Pipeline Reservation Charges assigned to Load Balancing.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
PR	Proportional Responsibility Allocator - A percentage representing a portion of capacity/product charges incurred in the off-peak season and assigned to the peak period calculated in each CGA filing as defined in Section 5.0.
RFopd	Off-peak demand charge reconciliation adjustment factor per billed off peak throughput volume associated with demand charges related to the off peak period.
Ropd	Reconciliation Costs - Account 175.11 balance, inclusive of the associated Account 175.11 interest, as outlined in Section 9.00.
SMBA	Simplified Market Based Allocator – Load Factor specific allocator as defined in Section 5.00
TR	Combined Tax rate as defined in Section 5.0
WCAopd	Demand charges allowable for working capital application as defined in Section 6.1.
WCFopd	Working Capital factor allowable per billed off-peak sales associated with demand charges allocated to the off-peak period as defined in Section 10.0
WCRopd	Working Capital reconciliation adjustment associated with off-peak demand charges balance account 175.14 balance as outlined in Section 10.0.
x	Designates Load Factor specific allocation of costs based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.
PS_{op}^{x}	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to off-peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Off-Peak Commodity Factor (CFop) Formula

$$CFop^{x} = \frac{Cop^{x} - NCCCop^{x}}{OP : Sales^{x}} + RFopc + WCFopc$$

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and:

$Cop^X = Sum{:}OPC^X - BOao^X - INJop^X - LIQop^X$

and:

$BOao^X = [(BOop - (BOvol \times (TPop/TPvolop)))\ MBA^X\ ]$

and:

RFopc = Ropc/OP:Sales

and:

$$WCFopc = \frac{\frac{[(WCAopc \times CC)-(WCAopc \times CD)]}{(1 - TR)} + (WCAopc \times CD) + WCRopc}{OP : Sales}$$

and:

WCAopc = Cop (DL/365)

Where:

BOao	LNG Boil-off allocation as defined in Section 9.00.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
Cop	Commodity Charges billed to the off-peak period as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers. See Section 10.00.
INJop	Injections into underground storage during the off-peak period.
LIQop	Liquefactions into storage during the off-peak period.
NCCCop	Non-core commodity costs allocated to the off-peak period as defined in Section 6.05.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
OPC	Commodity charges associated with gas supply sent out in the off-peak season as defined in Section 5.00.
RFopc	Off peak commodity charge reconciliation adjustment factor per billed off peak sales volume associated with commodity charges related to the off-peak period.
Ropc	Reconciliation Adjustment Cost - Account 175.13 balance, inclusive of the associated

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	Account 175.13 interest, as outlined in Section 9.00.
TPop	Total pipeline commodity purchase charges for the off-peak period.
TPvolop	Total pipeline purchase volumes for the off-peak period.
TR	Combined Tax rate as defined in Section 5.00.
WCAopc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFopc	Working Capital allowable per off-peak sales volume associated with commodity charges allocated to the off-peak period as defined in Section 10.00.
WCRopc	Working Capital reconciliation adjustment associated with off-peak commodity charges- Account 176.14 balance, as outlined in Section 10.00.
x	Designates Load Factor specific allocation of costs, based on Simplified Market Based Allocation factors.

7.0 Interruptible Sales, Off-System Sales and Capacity Release Revenues

A threshold level of margins will be established annually and separately for Interruptible Sales, Off-System Sales and Capacity Release Revenues. Any margins earned in excess of the predetermined level shall be divided between the Company and its firm sales customers under a 25/75 sharing arrangement. The threshold level of margins shall be adjusted to reflect additions or losses from Customers who switch from FT, FS or Interruptible Transportation ("IT") to IS and conversely, from IS to FT, FS or IT. The Company shall adjust the threshold level annually to reflect Interruptible Sales, Off-System sales, and capacity release revenues for the twelve-month period ending April 30 of each year.

Margins from Interruptible Sales, Off-System Sales and Capacity Release will be reflected as separate credits in the peak season GAF and shall be calculated as the sum of the following:

(1) 100% of the margins earned up to the predetermined threshold level.
(2) 75% of the margins earned in excess of the predetermined threshold level.

8.0 Gas Suppliers' Refunds - Accounts 265.85 and 265.86

Refunds from upstream capacity suppliers and suppliers of gas are credited to Account 265.85, "Refund-November" if received during the months of March through August, and to Account 265.86 "Refund-May", if received during the months of September through February.

A refund program shall be initiated with each semiannual GAF filing and shall remain in effect for a period of one year. The balance in Account 265.85 shall be placed into a refund program with each November filing. The balance in Account 265.86 shall be placed into a refund program

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with each May filing. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. The Company shall track and report on all Account 265.85 and Account 265.86 activities. If during any twelve-month period commencing with the billing month of November for Account 265.85 and May for Account 265.86, the projected supplier refund factor is less than one-hundredth of a cent per therm ($0.0001), the respective supplier refund account balance shall be transferred into Account 175.26 or Account 175.16 for the November and May filings respectively.

Gas Supplier's Refund Factors

R1 The per unit supplier refund associated with the Refund – May program. The following formula shall be used to calculate the R1 factor.

$$R1 = \frac{R1\$ + I}{A{:}Sales}$$

Where:

R1$	Ending balance in Account 265.86 "Refund – May"
I	Total forecasted interest calculated on the R1$ balance computed at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

R2 The per unit supplier refund associated with the Refund – November program. The following formula shall be used to calculate the R2 factor.

$$R2 = \frac{R2\$ + I}{A{:}Sales}$$

Where:

R2$	Ending balance in Account 265.85 "Refund – November"
I	Total forecasted interest calculated on the R2$ balance computed at the Federal Reserve Prime Rate based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

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9.0 Reconciliation Adjustments – Other than Working Capital

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Capacity Costs Allowable per Peak Demand Formula shall be:

i. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the peak season.

ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.

iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Charges associated with peaking, production and storage capacity to serve firm load in the peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service.

v. Credits associated with Non-Core Sales Margins or economic benefits from capacity release, off-system sales for resale and interruptible sales margins allocated to the firm sales service.

vi. Credits associated with daily imbalance charges billed transportation customers in the peak period.

vii. Peak demand Carrying Charges as defined in Section 5.00.

(b) Gas Costs Allowable Per Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefaction into storage.

ii. Credit non-core commodity costs assigned to non-core customers to which the CGAC does not apply, as defined in Section 6.06 (NCCCp).

iii. Inventory finance charges (FC).

iv. Peak commodity Carrying Charges as defined in Section 5.00.

(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity and product demand procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with transmission capacity and product demand

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procured by the Company to serve firm load in excess of base load requirements in the off-peak period

iii. Credits associated with daily imbalance charges billed transportation customers in the off peak period.

iv. Off-peak demand Carrying Charges as defined in Section 5.00.

v. Other A & G and Acct. 851 charges associated with peaking production and storage capacity to serve firm load in the off-peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service

(d) Gas Costs Allowable Per Off-Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Credits associated with Non-core commodity costs from non-core sales to which the GAF is not applied, as defined in Section 5.00.

iii. Off-peak commodity Carrying Charges as defined in Section 5.00.

(2) Calculation of the Reconciliation Adjustments

Account 175 contains the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Peak Demand (Account 175.21), Peak Production and Storage Demand (175.22) ,Peak Commodity (Account 175.23), Off-Peak Demand (Account 175.11), Off-Peak Production and Storage Demand (175.12) and Off-Peak Commodity (Account 175.13). Account 175.21 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Peak Demand Factor for the High and Low Load Factor classes, (DFp^X) times monthly firm sales volumes forHigh and Low Load Factor classes, and the total capacity costs allowable per the peak demand formula. Account 175.22 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Peak Commodity Factor for the High and Low Load Factorclasses, (CFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total commodity costs allowable per the peak commodity formula. Account 175.22 shall contain the accumulated difference between revenues as calculated by multiplying the Peak Production and Storage Demand Factor for the High and Low Load Factor class, (PS_p^x) times monthly firm sales volumes forthe High and Low Load Factor classes, and the total production and storage costs allowable per the peak production and storage demand formula. Account 175.11 shall contain the accumulated difference between revenues toward capacity costs

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calculated by multiplying the Off-Peak Demand Factor for the High and Low Load Factor classes, ($DFop^{X}$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total capacity costs allowable per the off-peak demand formula. Account 175.13 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Off-Peak Commodity Factor for the High and Low Load Factor classes, ($CFop^{X}$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total commodity costs allowable per the off-peak commodity formula. Account 175.12 shall contain the accumulated difference between revenues as calculated by multiplying the Off-Peak Production and Storage Demand Factor for the High and Low Load Factor classes, (PS_{op}^{x}) times monthly firm sales volumes for the High and Low Load Factorclasses, and the total production and storage costs allowable per the off-peak production and storage demand formula.

Carrying Charges as defined in Section 5.00 shall be added to each end-of-the-month balance. The peak demand reconciliation adjustment factor (RFpd) shall be determined for use in the peak GAF calculation by dividing the peak demand account (175.21) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak production & storage demand reconciliation adjustment factor (RFppsd) shall be determined for use in the peak GAF calculation by dividing the peak production and storage demand account (175.22) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak commodity reconciliation adjustment factor (RFpc) shall be determined for use in the peak GAF calculation by dividing the peak commodity account (175.23) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The off-peak demand reconciliation adjustment factor (RFopd) shall be determined for use in the off peak GAF calculation by dividing the off-peak demand account (175.11) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak production and storage demand reconciliation adjustment factor (RFoppsd) shall be determined for use in the off-peak GAF calculation by dividing the off-peak production and storage demand account (175.12) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak commodity reconciliation adjustment factor (RFopc) shall be determined for use in the off-peak GAF calculation by dividing the off-peak commodity account (175.13) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period.

The peak period reconciliation will be filed thirty (30) days prior to the peak period GAF filing, which is seventy-five (75) days prior to the effective date.

The off-peak period reconciliation shall be filed thirty (30) days prior to the off-peak period GAF filing, which is seventy-five (75) days prior to the effective date.

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10.0 Working Capital Reconciliation Adjustments

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Working Capital Gas Costs Allowable Per Peak Demand Formula shall be:

i. Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the peak season.

ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.

iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Carrying Charges

(b) Working Capital Gas Costs Allowable Per Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average costs of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-Core Commodity Costs associated with non-core sales to which the GAF is not applied.

iii. Carrying charges.

(c) Working Capital Gas Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the off-peak period.

iii. Carrying charges.

(d) Working Capital Gas Costs Allowable Per Off-Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, procured by the company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes

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purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-core commodity costs associated with non-core sales to which the GAF is not applied, as defined in section 6.05.

iii. Carrying charges.

(2) The peak and off-peak, demand, and commodity working capital requirements shall be calculated by applying the Company's days lag divided by 365 days to the working capital costs allowable per each formula.

(3) The peak and off-peak, demand, and commodity working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working capital requirement to calculate the respective returns on working capital. The interest portion of each working capital allowance is calculated by multiplying each working capital requirement by the weighted cost of debt. This portion is tax deductible. The return on each working capital less the interest portion of each working capital is then divided by one minus the tax rate. This figure plus the interest calculated above equals the working capital allowance for each.

(4) Calculation of the Reconciliation Adjustments

Accounts 175.14, 175.13, 175.24, and 175.23 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company plus Carrying Charges as defined in Section 5.00.

The components of the Company's purchased gas days lag shall be recalculated each season based upon actual CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenues. Each Account 175 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

The peak demand working capital reconciliation adjustment shall be determined for use in the peak demand factor calculations incorporating the peak demand working capital account 175.14 balance as of the peak reconciliation date designated by the Company. A peak commodity working capital reconciliation adjustment shall be determined for use in the peak commodity factor calculations incorporating the peak commodity working capital account 175.13 balance as of the peak reconciliation date designated by the Company. An off-peak working

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capital reconciliation adjustment (WCRopd) shall be determined for use in the off -peak demand factor calculations incorporating the off-peak demand working capital account (175.24) balance as of the off-peak reconciliation date designated by the Company. An off-peak commodity working capital reconciliation adjustment (WCRopc) shall be determined for use in the off-peak commodity working capital account (175.23) balance as of the off-peak reconciliation date designated by the Company.

11.0 Application of GAF to Bills

The Company will employ the GAFs as follows: The peak season rates to each Load Factor class shall be calculated by adding the respective peak demand factor and the peak commodity factor. The off-peak season rates to each Load Factor class shall be calculated by adding the respective off-peak demand factor and the off-peak commodity factor. The GAFs ($/therm) for each Load Factor class for each season shall be calculated to the nearest one-hundredth of a cent per therm ($0.0001) and will be applied to each customer's monthly sales volume within the corresponding Load Factor class.

12.0 Information Required to be Filed with the Department

Information pertaining to the cost of gas adjustment shall be filed with the Department in accordance with the Company's standardized forms approved by the Department. Required filings include a semiannual GAF filing which shall be submitted to the Department at least 45 days before the date on which a new GAF is to be effective.

Additionally the Company shall file with the Department a complete list of all gas costs claimed as recoverable through the CGAC over the previous season, as included in the seasonal reconciliation. This information shall be submitted with each seasonal GAF filing, along with complete documentation of the reconciliation adjustment calculations.

13.0 Other Rules

(1) The Department may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

(2) The Company may, at any time, file with the Department an amended GAF. An amended GAF filing must be submitted 10 days before the first billing cycle of the month

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in which it is proposed to take effect.

(3) The Department may, at any time, require the Company to file an amended GAF.

(4) The operation of the cost of gas adjustment clause is subject to all powers of suspension and investigation vested in the Department by G.L. c.164.

14.0 Customer Notification

The Company will design a notice, which explains in simple terms to customers the GAF, the nature of any change in the GAF and the manner in which the GAF is applied to the bill. The Company will submit this notice for approval at the time of each GAF filing.

Upon approval by the Department, the Company must immediately distribute these notices to all of its customers either through direct mail or with its bills.

15.0 Bad Debt Allowance

15.01 Purpose

The purpose of this provision is to establish a procedure that, subject to the jurisdiction of the Department, allows Bay State to adjust, on a semi-annual basis, its rates for the recovery of Bad Debt Expense

15.02 Bad Debt (BDF) Formula

The Bad Debt (BDF) Formula shall be computed on an annual basis using forecasts of bad debt expense associated with gas costs, gas costs, carrying charges, sales volumes, and a working capital allowance. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing. The forecast of bad debt expense associated with gas costs shall be based on the Company's projected gas costs in the respective seasonal GAF filings and the percent of net write-offs to total firm revenues as determined in the Company's last rate proceeding.

The calculation at the beginning of the off-peak season shall be on a projected annual basis. The calculation at the beginning of the peak season will update the remaining months of the projected annual period with actual bad debt expenses and collections for the available months and projections for the remaining months of the annual period. The following formula shall be used to calculate the Bad Debt factor.

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$$BDF = \frac{BD + RAbd + WCbd + I}{A{:}Sales}$$

and:

$$WCbd = \frac{(WCAbd * CC) - (WCAbd * CD)}{(1 - TR)} + (WCAbd * CD)$$

and:

$$WCAbd = BD * (DL/365)$$

Where:

A:Sales Forecast annual sales volumes.

BD Forecast Bad Debt Expense as defined in Section 5.00; derived by multiplying the forecast annual gas costs by the percent of annual net write-offs to annual firm revenues as determined in D.T.E. 05-27~~the Company's last rate case~~.

CC Weighted cost of capital as defined in Section 5.00.

CD Weighted cost of debt as defined in Section 5.00.

DL Number of days lag from the purchase of gas from suppliers to the payment by customers.

I Interest on total bad debt allowance plus working capital on bad debt calculated at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.

RAbd Bad Debt Expense reconciliation adjustment - Account 175.31 balance.

TR Combined Tax rate as defined in Section 5.00.

WCAbd Bad Debt allowable for working capital application defined as the costs associated with the gas cost portion of bad debt incurred by the Company to serve firm load.

WCbd Working Capital Allowance associated with the gas portion of bad debt for the period including the Pretax Weighted Cost of Capital as defined in Section 5.00.

15.03 Bad Debt Reconciliation Adjustment

Account 175.31 shall contain the accumulated difference between the annual revenues toward bad debt, as calculated by multiplying the bad debt factors (BDF) times monthly firm sales volumes, and the annual allowed Bad Debt expenses, allowed working capital on Bad Debt and Carrying Charges as defined in Section 5.00.

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An annual bad debt reconciliation adjustment (RAbd - as defined in Section 15.02) shall be determined for use in the bad debt factor calculations incorporating the bad debt working capital account (175.32) balance as of the reconciliation date designated by the Company.

(a) Costs Allowable per Bad Debt Formula shall be:

i. Un-collectable gas costs incurred by the Company to serve firm sales load, as determined by deriving the portion of actual net write-offs associated with gas cost collections.

ii. Account 175.32 – Bad Debt, Carrying Charges.

iii. Working Capital Gas Costs Allowable per Bad Debt Formula, which shall be charges associated with bad debt incurred by the Company to serve firm sales load and applied to the working capital formula.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 1, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

RR-DTE-104: Please determine if there is a cell reference or formula error in Line 95 of Schedule JAF-2-1, at page 4, for the rate classes G-42, G-53, G-43 and G-52. If an error exists, please provide both hard and electronic corrected copies of all workpapers and schedules impacted by the change.

Response: It has been determined that a cell reference or formula error exists in Line 95 of Schedule JAF-2-1, where it is intended to combine the indirect gas costs and resulting rates of C&I 42 and 43 classes and C&I 52 and 53 classes. The correction of this error has been reflected in Attachment RR-DTE-104, which is a revised Schedule JAF-2-1. An electronic copy of this revised worksheet (Schedule JAF-2-1, along with all other affected schedules (JAF-2-5 and JAF-2-10) is also provided to the Department on a compact disc accompanying this response.

The revision involved changing the references on line 95, page 4, (Indirect Gas Adjustment Factor - Summer) as follows:

- Column C&I (52) – Sum both the Summer C&I 52 & 53 classes' costs on Line 86, rather than the Summer C&I 52 and Winter C&I 43 classes' costs; and
- Column C&I (42) – Sum both the Summer C&I 42 & 43 classes' costs on Line 86, rather than the Summer C&I 42 and Summer C&I 52 classes' costs.

These revisions resulted in changing the indirect gas cost rate of the C&I 42/43 classes from $0.0833 per therm to $0.0597 per therm; and the C&I 52/53 classes from $0.0682 per therm to $0.0617 per therm. Note that the revision to these rates also impacted gas cost revenues imputed for the transportation customers, reducing such revenues shown on line 121 of Schedule JAF-2-1 from $25,858,200 to $25,518,413. These revisions also resulted in very minor changes to the final rates run through the rate design process.

Bay State Gas Company
Rate Design

line	Description	Residential Heating Total	Residential Heating R&T-3	Residential Heating (4) Low-Income	Residential Non-Heating Total	Residential Non-Heating R&T-1	Residential Non-Heat (2) Low-Income	Outdoor Lighting	C&I (40) Low Annual High Winter	C&I (50) Low Annual Low Winter	C&I (41) Med. Annual High Winter	C&I (51) Med. Annual Low Winter
1	**CURRENT BASE RATES**											
2	Monthly Customer Charge		$7.47	$5.97		$7.46	$5.97	$3.32	$12.61	$12.61	$45.04	$45.04
3	Winter Volumetric Rates											
4	First Block Rate		$0.4000	$0.2247		$0.4349	$0.2869		$0.3694	$0.3597	$0.1979	$0.1708
5	Second Block Rate		$0.2076	$0.0709		$0.3758	$0.2396		$0.2315	$0.2268	$0.1572	$0.1315
6	Summer Volumetric Rates											
7	First Block Rate		$0.2317	$0.1243		$0.3848	$0.2517		$0.3288	$0.3240	$0.1246	$0.1000
8	Second Block Rate		$0.1639	$0.0700		$0.2965	$0.1811		$0.1855	$0.1884	$0.0988	$0.0765
9	Demand Rate											
10	Winter											
11	Summer											
12												
13	First Block Size											
14	Winter		90	90		12	12		125	125	1,000	700
15	Summer		30	30		10	10		35	80	300	500
16												
17	**TEST YEAR BILLING DETERMINANTS**											
18	**Number of Bills**											
19	Sales Customers - Annual	2,666,054	2,449,833	216,221	400,456	380,442	20,014	144	190,903	35,847	43,826	15,250
20	Sales Customers - Winter	1,341,210	1,227,579	113,631	194,724	184,413	10,311	72	96,712	18,101	21,670	7,692
21	Sales Customers - Summer	1,324,844	1,222,254	102,590	205,732	196,029	9,703	72	94,191	17,746	22,156	7,558
22												
23	Transportation - Annual	440	440	0	59	59	0	0	9,303	4,061	12,369	5,823
24	Transportation - Winter	223	223	0	29	29	0	0	4,602	2,070	6,291	3,026
25	Transportation - Summer	217	217	0	30	30	0	0	4,701	1,991	6,078	2,797
26												
27	Total - Annual	2,666,494	2,450,273	216,221	400,515	380,501	20,014	144	200,206	39,908	56,195	21,073
28	Total - Winter	1,341,433	1,227,802	113,631	194,753	184,442	10,311	72	101,314	20,171	27,961	10,718
29	Total - Summer	1,325,061	1,222,471	102,590	205,762	196,059	9,703	72	98,892	19,737	28,234	10,355
30												
31	**First Block Therms**											
32	Sales Customers - Winter	107,074,126	98,497,478	8,576,648	1,687,563	1,604,160	83,403	1,395	8,836,019	1,240,429	17,789,142	4,608,855
33	Sales Customers - Summer	30,311,351	27,899,767	2,411,584	1,464,808	1,389,153	75,655	1,333	1,131,629	736,181	2,742,440	3,120,285
34												
35	Transportation Customers - Winter	18,105	18,105	0	306	306	0	0	505,134	155,589	5,568,728	1,960,146
36	Transportation Customers- Summer	5,269	5,269	0	265	265	0	0	89,954	98,920	1,118,124	1,236,700
37												
38	Total First Block - Winter	107,092,231	98,515,583	8,576,648	1,687,869	1,604,466	83,403	1,395	9,341,153	1,396,018	23,357,870	6,569,001
39	Total First Block- Summer	30,316,620	27,905,036	2,411,584	1,465,073	1,389,418	75,655	1,333	1,221,583	835,101	3,860,564	4,356,985
40												
41	**Second Block Therms**											
42	Sales Customers - Winter	94,806,098	86,404,748	8,401,350	2,053,651	1,856,385	197,266	0	12,040,801	1,371,743	15,722,941	3,507,671
43	Sales Customers - Summer	15,512,165	13,758,545	1,753,620	1,188,236	1,078,831	109,405	0	1,302,761	1,097,851	2,381,956	2,482,096
44												
45	Transportation Customers - Winter	44,795	44,795	0	721	721	0	0	1,115,993	342,115	7,439,176	2,664,232
46	Transportation Customers- Summer	11,380	11,380	0	616	616	0	0	188,945	201,158	1,398,085	1,789,398
47												
48	Total Second Block - Winter	94,850,893	86,449,543	8,401,350	2,054,372	1,857,106	197,266	0	13,156,794	1,713,858	23,162,117	6,171,903
49	Total Second Block- Summer	15,523,545	13,769,925	1,753,620	1,188,852	1,079,447	109,405	0	1,491,706	1,299,009	3,780,041	4,271,494
50												
51	**Total Therms**											
52	Total Therms - Annual	247,783,289	226,640,087	21,143,202	6,396,166	5,930,437	465,729	2,728	25,211,236	5,243,986	54,160,592	21,369,383
53	Total Therms - Winter	201,943,124	184,965,126	16,977,998	3,742,241	3,461,572	280,669	1,395	22,497,947	3,109,876	46,519,987	12,740,904
54	Total Therms - Summer	45,840,165	41,674,961	4,165,204	2,653,925	2,468,865	185,060	1,333	2,713,289	2,134,110	7,640,605	8,628,479
55	**Peak Day Therms**											
56	Total Peak Therms - Winter											
57	Total Peak Therms - Summer											

Bay State Gas Company
Rate Design

line	Description	C&I (42) High Annual High Winter	C&I (52) High Annual Low Winter	C&I (43) Ex. High Ann. High Winter	C&I (53) Ex. High Ann. Low Winter	Special Contract	Company Total	Notes
1	**CURRENT BASE RATES**							
2	Monthly Customer Charge	$109.37	$109.37	$298.53	$298.53			
3	Winter Volumetric Rates							
4	First Block Rate	$0.1658	$0.1638	$0.0389	$0.0389			
5	Second Block Rate	$0.1317	$0.1288					
6	Summer Volumetric Rates							
7	First Block Rate	$0.0687	$0.0712	$0.0170	$0.0170			
8	Second Block Rate	$0.0573	$0.0569					
9	Demand Rate							
10	Winter			$1.9787	$1.9787			
11	Summer			$0.8723	$0.8723			
12								
13	First Block Size							
14	Winter	9,000	10,000					
15	Summer	2,200	8,000					
16								
17	**TEST YEAR BILLING DETERMINANTS**							
18	**Number of Bills**							Linked to Revenue File
19	Sales Customers - Annual	3,331	1,100	61	91	0		line 20 + line 21
20	Sales Customers - Winter	1,612	558	32	56	0		
21	Sales Customers - Summer	1,719	542	29	35	0		
22								
23	Transportation - Annual	4,101	1,889	120	708	60		line 24 + line 25
24	Transportation - Winter	2,050	972	60	354	30		
25	Transportation - Summer	2,051	917	60	354	30		
26								
27	Total - Annual	7,432	2,989	181	799	60	3,395,996	line 28 + line 29
28	Total - Winter	3,662	1,530	92	410	30	1,702,146	line 20 + line 24
29	Total - Summer	3,770	1,459	89	389	30	1,693,850	line 21 + line 25
30								
31	**First Block Therms**							
32	Sales Customers - Winter	10,546,755	3,147,730	3,128,697	2,286,988	0		
33	Sales Customers - Summer	1,723,995	2,077,886	1,303,249	867,009	0		
34								
35	Transportation Customers - Winter	14,755,633	7,257,566	4,082,507	26,368,965	68,058,131		
36	Transportation Customers- Summer	2,478,355	5,128,242	953,578	24,699,265	48,156,552		
37								
38	Total First Block - Winter	25,302,388	10,405,296	7,211,204	28,655,953	68,058,131		line 32 + line 35
39	Total First Block- Summer	4,202,350	7,206,128	2,256,827	25,566,274	48,156,552		line 33 + line 36
40								
41	**Second Block Therms**							
42	Sales Customers - Winter	4,052,965	656,853	0	0	0		
43	Sales Customers - Summer	1,159,973	783,422	0	0	0		
44								
45	Transportation Customers - Winter	7,451,026	3,694,479	0	0	0		
46	Transportation Customers- Summer	1,966,704	2,759,090	0	0	0		
47								
48	Total Second Block - Winter	11,503,991	4,351,332	0	0	0		line 42 + line 45
49	Total Second Block- Summer	3,126,677	3,542,512	0	0	0		line 43 + line 46
50								
51	**Total Therms**							
52	Total Therms - Annual	44,135,406	25,505,268	9,468,031	54,222,227	116,214,683	609,712,995	line 53 + line 54
53	Total Therms - Winter	36,806,379	14,756,628	7,211,204	28,655,953	68,058,131	446,043,769	line 38 + line 48
54	Total Therms - Summer	7,329,027	10,748,640	2,256,827	25,566,274	48,156,552	163,669,226	line 39 + line 49
55	**Peak Day Therms**							
56	Total Peak Therms - Winter			342,526	1,388,815			
57	Total Peak Therms - Summer			103,257	1,184,822			

Bay State Gas Company
Rate Design

line	Description	Residential Heating Total	Residential Heating R&T-3	Residential Heating (4) Low-Income	Residential Non-Heating Total	Residential Non-Heating R&T-1	Residential Non-Heat (2) Low-Income	Outdoor Lighting	C&I (40) Low Annual High Winter	C&I (50) Low Annual Low Winter	C&I (41) Med. Annual High Winter	C&I (51) Med. Annual Low Winter
58												
59	**TEST YEAR REVENUE AND AVERAGE RATES**											
60	**Base Revenue Proof**											
61	Customer Revenue											
62	Winter	$9,850,058	$9,171,681	$678,377	$1,437,494	$1,375,937	$61,557	$239	$1,277,570	$254,356	$1,259,363	$482,739
63	Summer	$9,744,321	$9,131,858	$612,462	$1,520,527	$1,462,600	$57,927	$239	$1,247,028	$248,884	$1,271,659	$466,389
64	Volumetric Revenue - First Block											
65	Winter	$41,333,406	$39,406,233	$1,927,173	$721,711	$697,782	$23,928	$0	$3,450,622	$502,148	$4,622,522	$1,121,985
66	Summer	$6,765,357	$6,465,597	$299,760	$553,690	$534,648	$19,042	$0	$401,656	$270,573	$481,026	$435,699
67	Volumetric Revenue - Second Block											
68	Winter	$18,542,581	$17,946,925	$595,656	$745,165	$697,900	$47,265	$0	$3,045,798	$388,703	$3,641,085	$811,605
69	Summer	$2,379,644	$2,256,891	$122,753	$339,869	$320,056	$19,813	$0	$276,711	$244,733	$373,468	$326,769
70	Demand Revenue											
71	Winter											
72	Summer											
73	Total Base Revenue											
74	Annual	$88,615,366	$84,379,185	$4,236,181	$5,318,457	$5,088,924	$229,532	$478	$9,699,385	$1,909,397	$11,649,124	$3,645,186
75	Winter	$69,726,045	$66,524,839	$3,201,206	$2,904,370	$2,771,620	$132,750	$239	$7,773,989	$1,145,207	$9,522,971	$2,416,329
76	Summer	$18,889,322	$17,854,346	$1,034,976	$2,414,087	$2,317,304	$96,783	$239	$1,925,396	$764,190	$2,126,154	$1,228,857
77												
78	**Test Year Revenues Other Than Base**											
79	Direct Gas Adjustment Factor											
80	Winter	$174,520,722	$159,967,958	$14,552,764	$2,954,414	$2,734,150	$220,264	$1,046	$18,045,768	$2,077,451	$27,427,776	$6,173,431
81	Summer	$37,128,614	$33,832,934	$3,295,680	$2,083,413	$1,941,005	$142,408	$1,020	$2,072,310	$1,426,365	$4,348,236	$4,371,925
82	Indirect Gas Adjustment Factor											
83	Winter	$10,654,378	$9,770,054	$884,324	$140,140	$129,799	$10,341	$46	$1,042,083	$119,382	$1,627,923	$320,877
84	Summer	$2,625,689	$2,387,022	$238,667	$153,346	$142,650	$10,696	$79	$136,326	$106,741	$299,777	$329,979
85	Distribution Adjustment Factor											
86	Winter	$2,770,292	$2,543,322	$226,970	$20,423	$19,096	$1,327	$2	$264,368	$37,414	$549,519	$157,285
87	Summer	$715,107	$650,130	$64,977	$32,908	$30,614	$2,294	$6	$55,351	$43,536	$155,868	$176,021
88												
89	**Test Year Average Rates**											
90	Direct Gas Adjustment Factor											
91	Winter		$0.8645	$0.8645		$0.7897	$0.7897	$0.7498	$0.8644	$0.7953	$0.8184	$0.7606
92	Summer		$0.8103	$0.8103		$0.7853	$0.7853	$0.7652	$0.8513	$0.7777	$0.8485	$0.7804
93	Indirect Gas Adjustment Factor											
94	Winter		$0.0528	$0.0528		$0.0375	$0.0375	$0.0330	$0.0499	$0.0457	$0.0486	$0.0395
95	Summer		$0.0573	$0.0573		$0.0578	$0.0578	$0.0593	$0.0560	$0.0582	$0.0585	$0.0589
96	Distribution Adjustment Factor											
97	Winter		$0.0137	$0.0137		$0.0055	$0.0055	$0.0014	$0.0119	$0.0119	$0.0119	$0.0119
98	Summer		$0.0156	$0.0156		$0.0124	$0.0124	$0.0045	$0.0204	$0.0204	$0.0204	$0.0204
99	Deferred Gas Cost Factor											
100	Winter		$0.0467	$0.0467		$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467
101	Summer		$0.0467	$0.0467		$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467	$0.0467
102												
103	**Imputed Gas Costs for Trans. Cust. (TY)**											
104	Direct Gas Adjustment Factor											
105	Winter	$57,311	$57,311	$0	$859	$859	$0	$0	$1,476,953	$419,052	$11,253,365	$3,733,137
106	Summer	$14,267	$14,267	$0	$733	$733	$0	$0	$250,434	$247,382	$2,252,534	$2,502,711
107	Indirect Gas Adjustment Factor											
108	Winter	$3,320	$3,320	$0	$38	$38	$0	$0	$80,920	$22,746	$631,887	$182,819
109	Summer	$954	$954	$0	$51	$51	$0	$0	$15,618	$17,465	$147,198	$178,237

Bay State Gas Company
Rate Design

line	Description	C&I (42) High Annual High Winter	C&I (52) High Annual Low Winter	C&I (43) Ex. High Ann. High Winter	C&I (53) Ex. High Ann. Low Winter	Special Contract	Company Total	Notes
58								
59	**TEST YEAR REVENUE AND AVERAGE RATES**							
60	**Base Revenue Proof**							
61	Customer Revenue							
62	Winter	$400,513	$167,336	$27,465	$122,397	$1,673,238		line 2 * line 28
63	Summer	$412,325	$159,571	$26,569	$116,128	$1,700,847		line 2 * line 29
64	Volumetric Revenue - First Block							
65	Winter	$4,195,136	$1,704,387	$280,516	$1,114,717	$73,688		line 4 * line 38
66	Summer	$288,701	$513,076	$38,366	$434,627	$54,492		line 7 * line 39
67	Volumetric Revenue - Second Block							
68	Winter	$1,515,076	$560,452					line 5 * line 48
69	Summer	$179,159	$201,569					line 8 * line 49
70	Demand Revenue							
71	Winter			$677,756	$2,748,048	$0		line 10 * line 57
72	Summer			$90,071	$1,033,520	$0		line 11 * line 58
73	Total Base Revenue							
74	Annual	$6,990,909	$3,306,391	$1,140,743	$5,569,437	$3,502,265	$141,347,140	line 75 + line 76
75	Winter	$6,110,724	$2,432,175	$985,737	$3,985,162	$1,746,926	$108,749,875	line 62 + line 65 + line 68 + line 71
76	Summer	$880,185	$874,216	$155,006	$1,584,275	$1,755,339	$32,597,265	line 63 + line 66 + line 69 + line 72
77								
78	**Test Year Revenues Other Than Base**							
79	Direct Gas Adjustment Factor						$307,478,651	
80	Winter	$11,386,539	$2,931,479	$2,283,880	$1,820,147		$249,622,653	
81	Summer	$2,406,876	$2,249,653	$1,097,293	$670,293		$57,855,998	
82	Indirect Gas Adjustment Factor							
83	Winter	$701,197	$150,322	$143,101	$98,211		$14,997,660	
84	Summer	$172,174	$176,541	$77,805	$53,494		$4,131,951	
85	Distribution Adjustment Factor							
86	Winter	$434,212	$182,500	$79,946	$351,731		$4,847,692	
87	Summer	$149,511	$219,272	$46,039	$521,551		$2,115,170	
88								
89	**Test Year Average Rates**							
90	Direct Gas Adjustment Factor							Some classes are combined.
91	Winter	$0.7711	$0.7800	$0.7711	$0.7800			line 80 / (line 32 + line 42)
92	Summer	$0.8369	$0.7832	$0.8369	$0.7832			line 81 / (line 33 + line 43)
93	Indirect Gas Adjustment Factor							
94	Winter	$0.0476	$0.0408	$0.0476	$0.0408			line 83 / (line 32 + line 42)
95	Summer	$0.0597	$0.0617	$0.0597	$0.0617			line 84 / (line 33 + line 43)
96	Distribution Adjustment Factor							
97	Winter	$0.0119	$0.0119	$0.0119	$0.0119			line 86 / line 53
98	Summer	$0.0204	$0.0204	$0.0204	$0.0204			line 87 / line 54
99	Deferred Gas Cost Factor							
100	Winter	$0.0467	$0.0467	$0.0467	$0.0467			INPUT from COS
101	Summer	$0.0467	$0.0467	$0.0467	$0.0467			INPUT from COS
102								
103	**Imputed Gas Costs for Trans. Cust. (TY)**							Calculated using average rates and
104	Direct Gas Adjustment Factor							transportation volumes.
105	Winter	$18,160,054	$9,054,121	$3,338,573	$21,799,382		$69,292,806	(line 91 + line 100) * (line 35 + line 45)
106	Summer	$3,927,415	$6,545,332	$842,530	$20,496,779		$37,080,117	(line 92 + line 101) * (line 36 + line 46)
107	Indirect Gas Adjustment Factor							
108	Winter	$1,057,570	$446,838	$194,425	$1,075,840		$3,696,404	line 94 * (line 35 + line 45)
109	Summer	$265,372	$486,644	$56,929	$1,523,930		$2,692,398	line 95 * (line 36 + line 46)

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110												
111	**Summary of TY Rev. w/ Imputed Gas Costs**											
112	Test Year Base Revenue											
113	Annual	$88,615,366	$84,379,185	$4,236,181	$5,318,457	$5,088,924	$229,532	$478	$9,699,385	$1,909,397	$11,649,124	$3,645,186
114	Winter	$69,726,045	$66,524,839	$3,201,206	$2,904,370	$2,771,620	$132,750	$239	$7,773,989	$1,145,207	$9,522,971	$2,416,329
115	Summer	$18,889,322	$17,854,346	$1,034,976	$2,414,087	$2,317,304	$96,783	$239	$1,925,396	$764,190	$2,126,154	$1,228,857
116	Direct Cost of Gas Revenue											
117	Annual	$211,720,914	$193,872,470	$17,848,444	$5,039,419	$4,676,747	$362,672	$2,066	$21,845,465	$4,170,250	$45,281,911	$16,781,203
118	Winter	$174,578,033	$160,025,269	$14,552,764	$2,955,273	$2,735,009	$220,264	$1,046	$19,522,721	$2,496,503	$38,681,141	$9,906,568
119	Summer	$37,142,881	$33,847,201	$3,295,680	$2,084,146	$1,941,738	$142,408	$1,020	$2,322,744	$1,673,747	$6,600,770	$6,874,636
120	Indirect Cost of Gas Revenue											
121	Annual	$13,284,341	$12,161,350	$1,122,991	$293,575	$272,538	$21,037	$125	$1,274,947	$266,334	$2,706,786	$1,011,912
122	Winter	$10,657,698	$9,773,374	$884,324	$140,178	$129,837	$10,341	$46	$1,123,003	$142,128	$2,259,810	$503,696
123	Summer	$2,626,643	$2,387,976	$238,667	$153,397	$142,701	$10,696	$79	$151,944	$124,206	$446,975	$508,216
124	Deferred Gas Costs											
125	Annual	$11,561,095	$10,574,277	$986,818	$298,440	$276,703	$21,737	$127	$1,088,006	$207,518	$1,803,283	$640,304
126	Winter	$9,422,371	$8,629,955	$792,415	$174,614	$161,514	$13,100	$65	$974,385	$121,918	$1,564,112	$378,823
127	Summer	$2,138,724	$1,944,321	$194,403	$123,826	$115,188	$8,637	$62	$113,620	$85,600	$239,171	$261,480
128	LDAC Revenue											
129	Annual	$3,485,399	$3,193,452	$291,947	$53,331	$49,710	$3,621	$8	$319,719	$80,950	$705,387	$333,306
130	Winter	$2,770,292	$2,543,322	$226,970	$20,423	$19,096	$1,327	$2	$264,368	$37,414	$549,519	$157,285
131	Summer	$715,107	$650,130	$64,977	$32,908	$30,614	$2,294	$6	$55,351	$43,536	$155,868	$176,021
132	Total											
133	Annual	$328,667,115	$304,180,734	$24,486,381	$11,003,222	$10,364,622	$638,599	$2,804	$34,227,522	$6,634,448	$62,146,491	$22,411,911
134	Winter	$267,154,438	$247,496,759	$19,657,679	$6,194,858	$5,817,077	$377,782	$1,398	$29,658,467	$3,943,170	$52,577,553	$13,362,701
135	Summer	$61,512,677	$56,683,974	$4,828,702	$4,808,363	$4,547,546	$260,818	$1,406	$4,569,056	$2,691,279	$9,568,938	$9,049,209
136												
137	**COST STUDY INFORMATION**											
138												
139	Target ACS Base Revenue											
140	Annual	$100,492,047			$10,856,303			$345	$11,303,039	$2,347,139	$12,855,832	$4,199,180
141	Winter	$67,185,084			$5,808,404			$243	$7,702,146	$1,390,455	$10,179,177	$2,876,642
142	Summer	$33,306,963			$5,047,899			$101	$3,600,893	$956,684	$2,676,656	$1,322,539
143												
144	Direct Gas Cost for New Rates											
145	Annual	$220,161,443	$201,369,526	$18,791,916	$5,553,949	$5,149,614	$404,335	$2,374	$20,721,910	$3,861,651	$34,343,363	$11,913,936
146	Winter	$179,486,460	$164,391,763	$15,094,697	$3,213,507	$2,972,427	$241,080	$1,198	$18,561,038	$2,243,719	$29,794,722	$6,971,671
147	Summer	$40,674,983	$36,977,763	$3,697,220	$2,340,442	$2,177,187	$163,255	$1,176	$2,160,872	$1,617,932	$4,548,641	$4,942,265
148												
149	Indirect Gas Cost for New Rates											
150	Annual	$12,195,262	$11,164,011	$1,031,251	$230,087	$212,979	$17,108	$90	$1,219,427	$160,448	$1,979,482	$497,484
151	Winter	$11,365,857	$10,409,995	$955,861	$200,903	$185,831	$15,072	$75	$1,175,365	$140,274	$1,886,730	$435,857
152	Summer	$829,406	$754,015	$75,390	$29,183	$27,148	$2,036	$15	$44,062	$20,174	$92,752	$61,626
153												
154	Direct Cost of Gas Rates (New)											
155	Winter	$0.8891	$0.8891	$0.8891	$0.8589	$0.8589	$0.8589	$0.8589	$0.8891	$0.8589	$0.8891	$0.8589
156	Summer	$0.8876	$0.8876	$0.8876	$0.8822	$0.8822	$0.8822	$0.8822	$0.8876	$0.8822	$0.8876	$0.8822
157	Indirect Cost of Gas Rates (New)											
158	Winter	$0.0563	$0.0563	$0.0563	$0.0537	$0.0537	$0.0537	$0.0537	$0.0563	$0.0537	$0.0563	$0.0537
159	Summer	$0.0181	$0.0181	$0.0181	$0.0110	$0.0110	$0.0110	$0.0110	$0.0181	$0.0110	$0.0181	$0.0110
160												
161	Target Customer Charge-MCOS	$32.45			$33.41				$47.73	$51.52	$85.47	$82.21
162	Target Customer Charge-ACS	$23.30			$24.22			$0.61	$34.63	$42.57	$82.80	$89.22
163	Unit Marginal Cost ($ / winter therm)	$0.1156			$0.0652			NA	$0.1396	$0.0683	$0.1255	$0.0643
164	Unit Marginal Cost ($ / summer therm)	$0.0640			$0.0307			NA	$0.0804	$0.0324	$0.0711	$0.0306

Bay State Gas Company
Rate Design

line	Description	C&I (42) High Annual High Winter	C&I (52) High Annual Low Winter	C&I (43) Ex. High Ann. High Winter	C&I (53) Ex. High Ann. Low Winter	Special Contract	Company Total	Notes
110								
111	**Summary of TY Rev. w/ Imputed Gas Costs**							
112	Test Year Base Revenue							
113	Annual	$6,990,909	$3,306,391	$1,140,743	$5,569,437	$3,502,265		line 114 + line 115
114	Winter	$6,110,724	$2,432,175	$985,737	$3,985,162	$1,746,926		line 75
115	Summer	$880,185	$874,216	$155,006	$1,584,275	$1,755,339		line 76
116	Direct Cost of Gas Revenue							
117	Annual	$35,880,883	$20,780,586	$7,562,276	$44,786,601		$413,851,574	line 118 + line 119
118	Winter	$29,546,593	$11,985,600	$5,622,453	$23,619,529			line 80 + line 105
119	Summer	$6,334,291	$8,794,985	$1,939,823	$21,167,072			line 81 + line 106
120	Indirect Cost of Gas Revenue							
121	Annual	$2,196,313	$1,260,345	$472,260	$2,751,476		$25,518,413	line 122 + line 123
122	Winter	$1,758,767	$597,160	$337,526	$1,174,051			line 83 + line 108
123	Summer	$437,546	$663,185	$134,734	$1,577,424			line 84 + line 109
124	Deferred Gas Costs							$17,079,967
125	Annual	$816,017	$311,118	$206,853	$147,207		$17,079,967	line 126 + line 127
126	Winter	$681,414	$177,572	$146,026	$106,741			line 100 * (line 32 + line 42)
127	Summer	$134,604	$133,546	$60,827	$40,466			line 101 * (line 33 + line 43)
128	LDAC Revenue							
129	Annual	$583,723	$401,772	$125,985	$873,282		$6,962,862	line 130 + line 131
130	Winter	$434,212	$182,500	$79,946	$351,731			line 86
131	Summer	$149,511	$219,272	$46,039	$521,551			line 87
132	Total							
133	Annual	$46,467,846	$26,060,211	$9,508,117	$54,128,002		$601,257,691	line 134 + line 135
134	Winter	$38,531,710	$15,375,007	$7,171,688	$29,237,214			line 114 + line 118 + line 122 + line 126 + line 130
135	Summer	$7,936,136	$10,685,204	$2,336,429	$24,890,788			line 115 + line 119 + line 123 + line 127 + line 131
136								
137	**COST STUDY INFORMATION**							
138								
139	Target ACS Base Revenue							
140	Annual	$8,252,580	$3,549,167	$1,455,970	$5,790,935	$3,921,013	$161,102,537	line 141 + line 142
141	Winter	$6,953,781	$2,626,714	$1,284,399	$4,397,478		$110,404,524	without special contracts
142	Summer	$1,298,798	$922,452	$171,571	$1,393,457		$50,698,013	without special contracts
143								
144	Direct Gas Cost for New Rates							
145	Annual	$15,540,169	$5,792,104	$3,938,465	$2,729,254		$324,558,618	line 146 + line 147
146	Winter	$12,980,232	$3,267,937	$2,781,643	$1,964,403		$261,266,529	
147	Summer	$2,559,938	$2,524,167	$1,156,822	$764,851		$63,292,089	
148								
149	Indirect Gas Cost for New Rates							
150	Annual	$874,164	$235,780	$199,734	$132,348		$17,724,307	line 151 + line 152
151	Winter	$821,964	$204,306	$176,146	$122,811		$16,530,288	
152	Summer	$52,200	$31,474	$23,589	$9,537		$1,194,018	
153								
154	Direct Cost of Gas Rates (New)							
155	Winter	$0.8891	$0.8589	$0.8891	$0.8589			line 146 / (line 32 + line 42)
156	Summer	$0.8876	$0.8822	$0.8876	$0.8822			line 147 / (line 33 + line 43)
157	Indirect Cost of Gas Rates (New)							
158	Winter	$0.0563	$0.0537	$0.0563	$0.0537			line 151 / (line 32 + line 42)
159	Summer	$0.0181	$0.0110	$0.0181	$0.0110			line 152 / (line 33 + line 43)
160								
161	Target Customer Charge-MCOS	$351.39	$355.73	$1,001.16	$906.18			Linked to COS Schedules
162	Target Customer Charge-ACS	$261.13	$307.22	$799.10	$762.87			
163	Unit Marginal Cost ($ / winter therm)	$0.1134	$0.0543	$0.1272	$0.0618			
164	Unit Marginal Cost ($ / summer therm)	$0.0634	$0.0254	$0.0669	$0.0272			

Bay State Gas Company
Rate Design

Witness: J. A. Ferro
DTE-05-27
Exhibit BSG/JAF-2
Revised Schedule JAF-2-1
Attachment RR-DTE-104

line	Description	Residential Heating Total	Residential Heating R&T-3	Residential Heating (4) Low-Income	Residential Non-Heating Total	Residential Non-Heating R&T-1	Residential Non-Heat (2) Low-Income	Outdoor Lighting	C&I (40) Low Annual High Winter	C&I (50) Low Annual Low Winter	C&I (41) Med. Annual High Winter	C&I (51) Med. Annual Low Winter
165	**Imputed Gas Costs for Trans. Cust.**											
166	Direct Gas Adjustment Factor											
167	Winter	$57,311	$57,311	$0	$859	$859	$0	$0	$1,476,953	$419,052	$11,253,365	$3,733,137
168	Summer	$14,267	$14,267	$0	$733	$733	$0	$0	$250,434	$247,382	$2,252,534	$2,502,711
169	Indirect Gas Adjustment Factor											
170	Winter	$3,320	$3,320	$0	$38	$38	$0	$0	$80,920	$22,746	$631,887	$182,819
171	Summer	$954	$954	$0	$51	$51	$0	$0	$15,618	$17,465	$147,198	$178,237
172												
173	**Incremental LDAC Revenue**											
174												
175	Incremental LDAC Rate											
176	Winter	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114
177	Summer	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114
178	Incremental LDAC Revenue											
179	Winter	$2,303,953	$2,110,252	$193,701	$42,695	$39,493	$3,202	$16	$256,677	$35,480	$530,743	$145,360
180	Summer	$522,987	$475,466	$47,520	$30,278	$28,167	$2,111	$15	$30,956	$24,348	$87,171	$98,442
181												
182	**Revenue Other Than Base (New)**											
183												
184	Direct Cost of Gas Revenue											
185	Annual	$220,233,021	$201,441,105	$18,791,916	$5,555,541	$5,151,206	$404,335	$2,374	$22,449,297	$4,528,085	$47,849,261	$18,149,783
186	Winter	$179,543,771	$164,449,074	$15,094,697	$3,214,366	$2,973,286	$241,080	$1,198	$20,037,991	$2,662,770	$41,048,087	$10,704,807
187	Summer	$40,689,250	$36,992,030	$3,697,220	$2,341,175	$2,177,920	$163,255	$1,176	$2,411,306	$1,865,315	$6,801,175	$7,444,976
188	Indirect Cost of Gas Revenue											
189	Annual	$12,199,536	$11,168,284	$1,031,251	$230,176	$213,068	$17,108	$90	$1,315,966	$200,659	$2,758,567	$858,539
190	Winter	$11,369,176	$10,413,315	$955,861	$200,942	$185,870	$15,072	$75	$1,256,285	$163,020	$2,518,618	$618,677
191	Summer	$830,360	$754,969	$75,390	$29,234	$27,199	$2,036	$15	$59,681	$37,639	$239,950	$239,863
192	LDAC Revenue											
193	Annual	$6,312,338	$5,779,170	$533,168	$126,304	$117,370	$8,934	$39	$607,352	$140,778	$1,323,301	$577,108
194	Winter	$5,074,245	$4,653,574	$420,671	$63,118	$58,589	$4,529	$18	$521,045	$72,894	$1,080,262	$302,645
195	Summer	$1,238,094	$1,125,596	$112,497	$63,186	$58,781	$4,405	$21	$86,307	$67,884	$243,039	$274,463
196	Total											
197	Annual	$238,744,895	$218,388,559	$20,356,336	$5,912,021	$5,481,644	$430,377	$2,503	$24,372,615	$4,869,522	$51,931,130	$19,585,430
198	Winter	$195,987,192	$179,515,963	$16,471,229	$3,478,425	$3,217,744	$260,681	$1,291	$21,815,321	$2,898,685	$44,646,966	$11,626,129
199	Summer	$42,757,703	$38,872,596	$3,885,107	$2,433,596	$2,263,900	$169,696	$1,212	$2,557,294	$1,970,838	$7,284,164	$7,959,301
200												
201	**REVENUE ALLOCATION**											
202												
203	Percent ACS Base Revenue											
204	Annual	62.38%			6.74%			0.0002%	7.02%	1.46%	7.98%	2.61%
205	Winter	60.85%			5.26%			0.0002%	6.98%	1.26%	9.22%	2.61%
206	Summer	65.70%			9.96%			0.0002%	7.10%	1.89%	5.28%	2.61%
207	Base Revenue Requirement											
208	Other Fees Increase											
209	Revenue Assigned to Special Contracts											
210												
211	Incremental LDAC	$2,826,939			$72,973			$31	$287,633	$59,828	$617,914	$243,802
212	Remaining Revenue Requirement											
213	Target Allocation of Revenue Requirement	$96,950,986			$10,473,757			$333	$10,904,751	$2,264,432	$12,402,828	$4,051,213
214	Base Revenue Increment											
215	Total Revenue											
216	Test Year Revenue	$328,667,115			$11,003,222			$2,804	$34,227,522	$6,634,448	$62,146,491	$22,411,911
217	Target Revenue	$335,695,881			$16,385,778			$2,835	$35,277,366	$7,133,955	$64,333,958	$23,636,643
218	Increase at Target	$7,028,766			$5,382,556			$31	$1,049,844	$499,506	$2,187,467	$1,224,732
219	Percent Increase at Target	2.14%			48.92%			1.10%	3.07%	7.53%	3.52%	5.46%

Bay State Gas Company
Rate Design

line	Description	C&I (42) High Annual High Winter	C&I (52) High Annual Low Winter	C&I (43) Ex. High Ann. High Winter	C&I (53) Ex. High Ann. Low Winter	Special Contract	Company Total	Notes
165	**Imputed Gas Costs for Trans. Cust.**						$112,761,725	Hold Constant at Test Year Levels
166	Direct Gas Adjustment Factor						$112,761,725	
167	Winter	$18,160,054	$9,054,121	$3,338,573	$21,799,382		$69,292,806	line 105
168	Summer	$3,927,415	$6,545,332	$842,530	$20,496,779		$37,080,117	line 106
169	Indirect Gas Adjustment Factor							
170	Winter	$1,057,570	$446,838	$194,425	$1,075,840		$3,696,404	line 108
171	Summer	$265,372	$486,644	$56,929	$1,523,930		$2,692,398	line 109
172								
173	**Incremental LDAC Revenue**						$5,630,282	Exhibit BSG/JES-4
174								
175	Incremental LDAC Rate						$0.0114	line 173 / (total therms-special contracts)
176	Winter	$0.0114	$0.0114	$0.0114	$0.0114			Company Total: line 175
177	Summer	$0.0114	$0.0114	$0.0114	$0.0114			
178	Incremental LDAC Revenue						$5,630,282	check
179	Winter	$419,921	$168,357	$82,272	$326,933		$4,312,407	line 53 * line 176
180	Summer	$83,616	$122,630	$25,748	$291,684		$1,317,875	line 54 * line 177
181								
182	**Revenue Other Than Base (New)**							
183								
184	Direct Cost of Gas Revenue							
185	Annual	$37,627,638	$21,391,558	$8,119,568	$45,025,415		$430,931,541	line 186 + line 187
186	Winter	$31,140,285	$12,322,059	$6,120,216	$23,763,785		$330,559,335	line 146 + line 167
187	Summer	$6,487,352	$9,069,499	$1,999,352	$21,261,630		$100,372,206	line 147 + line 168
188	Indirect Cost of Gas Revenue							
189	Annual	$2,197,106	$1,169,262	$451,089	$2,732,119		$24,113,109	line 190 + line 191
190	Winter	$1,879,534	$651,144	$370,571	$1,198,652		$20,226,692	line 151 + line 170
191	Summer	$317,572	$518,118	$80,518	$1,533,467		$3,886,417	line 152 + line 171
192	LDAC Revenue							
193	Annual	$1,087,260	$692,760	$234,005	$1,491,899		$12,593,144	line 194 + line 195
194	Winter	$854,133	$350,857	$162,218	$678,664		$9,160,099	line 130 + line 179
195	Summer	$233,127	$341,902	$71,787	$813,235		$3,433,045	line 131 + line 180
196	Total							
197	Annual	$40,912,004	$23,253,580	$8,804,661	$49,249,433		$467,637,794	line 198 + line 199
198	Winter	$33,873,952	$13,324,060	$6,653,005	$25,641,101		$359,946,127	line 186 + line 190 + line 194
199	Summer	$7,038,052	$9,929,520	$2,151,657	$23,608,332		$107,691,667	line 187 + line 191 + line 195
200								
201	**REVENUE ALLOCATION**							
202								
203	Percent ACS Base Revenue							
204	Annual	5.12%	2.20%	0.90%	3.59%	NA	100.00%	line 140 / (company total - sp contracts)
205	Winter	6.30%	2.38%	1.16%	3.98%	NA	100.00%	line 141 / (company total - sp contracts)
206	Summer	2.56%	1.82%	0.34%	2.75%	NA	100.00%	line 142 / (company total - sp contracts)
207	Base Revenue Requirement						$165,023,551	
208	Other Fees Increase						**$46,525**	Schs. JAF-1-8, 1-10; Input
209	Revenue Assigned to Special Contracts					$3,921,013	$3,921,013	Test year plus allocated increase
210								
211	Incremental LDAC	$503,537	$290,988	$108,020	$618,617	$0	$5,630,282	line 179 + line 180
212	Remaining Revenue Requirement						$155,425,730	line 208 - sum (lines 208, 209, and 211)
213	Target Allocation of Revenue Requirement	$7,961,782	$3,424,104	$1,404,665	$5,586,879		$155,425,730	line 204 * Company Total line 212
214	Base Revenue Increment						$17,580,855	line 213 -(Company Total:line 74-Contracts:line 74)
215	Total Revenue							
216	Test Year Revenue	$46,467,846	$26,060,211	$9,508,117	$54,128,002		$601,257,691	line 133
217	Target Revenue	$48,873,786	$26,677,683	$10,209,327	$54,836,312		$623,063,524	line 197 + line 213
218	Increase at Target	$2,405,939	$617,472	$701,210	$708,310		$21,805,834	line 217 - line 216
219	Percent Increase at Target	5.18%	2.37%	7.37%	1.31%		3.63%	line 218 / line 216

Bay State Gas Company
Rate Design

Witness: J. A. Ferro
DTE-05-27
Exhibit BSG/JAF-2
Revised Schedule JAF-2-1
Attachment RR-DTE-104

line	Description	Residential Heating Total	Residential Heating R&T-3	Residential Heating (4) Low-Income	Residential Non-Heating Total	Residential Non-Heating R&T-1	Residential Non-Heat (2) Low-Income	Outdoor Lighting	C&I (40) Low Annual High Winter	C&I (50) Low Annual Low Winter	C&I (41) Med. Annual High Winter	C&I (51) Med. Annual Low Winter
220	**Revenue Increase Cap of 6%**	**$19,720,027**			**$660,193**			**$168**	**$2,053,651**	**$398,067**	**$3,728,789**	**$1,344,715**
221	Revenue to Re-allocate	NA			$4,722,363			NA	NA	$101,439	NA	NA
222												
223	Total Revenue to Re-allocate											
224	Test Year Revenue for Re-allocation	$328,667,115			NA			$2,804	$34,227,522	NA	$62,146,491	$22,411,911
225	Percent Assignment	57.25%						0.00%	5.96%		10.82%	3.90%
226	First Re-allocation	$2,836,362						$24	$295,380		$536,318	$193,412
227	Increase with First Re-allocation	$9,865,128			$660,193			$55	$1,345,224	$398,067	$2,723,785	$1,418,145
228	Revenue to Re-allocate	none			none			none	none	none	none	$73,430
229	Test Year Revenue for Re-allocation	$328,667,115			NA			NA	$34,227,522	NA	$62,146,491	NA
230	Percent Assignment	65.05%							6.77%		12.30%	
231	Second Re-allocation	$60,051							$6,254		$11,355	
232	Increase with Second Re-allocation	$9,925,180			$660,193			$55	$1,351,478	$398,067	$2,735,140	$1,344,715
233	Revenue to Re-allocate	none			none			none	none	none	none	none
234												
235												
236												
237												
238												
239												
240	Change from Target Allocation	$2,896,414			-$4,722,363			$24	$301,634	-$101,439	$547,673	$119,982
241												
242	**Base Revenue Requirement**	$99,847,400			$5,751,394			$357	$11,206,385	$2,162,993	$12,950,501	$4,171,195
243	Total Revenue Requirement	$338,592,295			$11,663,415			$2,860	$35,579,000	$7,032,515	$64,881,631	$23,756,625
244	Percent Increase	3.02%			6.00%			1.97%	3.95%	6.00%	4.40%	6.00%
245												
246												
247	**RATE DESIGN**											
248												
249	**Proposed Block Sizes**											
250												
251	First Block Size											
252	Winter		**125**	NA		**12**	NA	NA	NA	NA	NA	NA
253	Summer		**30**	NA		**10**	NA	NA	NA	NA	NA	NA
254												
255	Test Year Therms											
256	Annual	247,783,289	226,640,087	21,143,202	6,396,166	5,930,437	465,729	2,728	25,211,236	5,243,986	54,160,592	21,369,383
257	Winter	201,943,124	184,965,126	16,977,998	3,742,241	3,461,572	280,669	1,395	22,497,947	3,109,876	46,519,987	12,740,904
258	Summer	45,840,165	41,674,961	4,165,204	2,653,925	2,468,865	185,060	1,333	2,713,289	2,134,110	7,640,605	8,628,479
259												
260	Percent of Therms in Proposed 1st Block											
261	Winter	67.61%	67.61%	67.61%	45.10%	45.10%	45.10%	100.00%	100.00%	100.00%	100.00%	100.00%
262	Summer	66.14%	66.14%	66.14%	55.20%	55.20%	55.20%	100.00%	100.00%	100.00%	100.00%	100.00%
263												
264	Proposed First Block Therms											
265	Winter	136,533,746	125,054,922	11,478,824	1,687,869	1,561,278	126,591	1,395	22,497,947	3,109,876	46,519,987	12,740,904
266	Summer	30,316,620	27,905,036	2,411,584	1,465,073	1,389,418	75,655	1,333	2,713,289	2,134,110	7,640,605	8,628,479
267												
268	Proposed Second Block Therms											
269	Winter	65,409,378	59,910,204	5,499,174	2,054,372	1,900,294	154,078	0	0	0	0	0
270	Summer	15,523,545	13,769,925	1,753,620	1,188,852	1,079,447	109,405	0	0	0	0	0
271												
272	Base Revenue Requirement	$99,847,400			$5,751,394			$357	$11,206,385	$2,162,993	$12,950,501	$4,171,195
273												

line	Description	C&I (42) High Annual High Winter	C&I (52) High Annual Low Winter	C&I (43) Ex. High Ann. High Winter	C&I (53) Ex. High Ann. Low Winter	Special Contract	Company Total	Notes
220	**Revenue Increase Cap of 6%**	**$2,788,071**	**$1,563,613**	**$570,487**	**$3,247,680**			line 216 * 6%
221	Revenue to Re-allocate	NA	NA	$130,723	NA		$4,954,525	line 218 - line 220
222								
223	Total Revenue to Re-allocate						$4,954,525	line 221 - line 222
224	Test Year Revenue for Re-allocation	$46,467,846	$26,060,211	NA	$54,128,002		$574,111,904	line 216
225	Percent Assignment	8.09%	4.54%		9.43%		100.00%	line 224 / Company Total line 224
226	First Re-allocation	$401,013	$224,897		$467,119		$4,954,525	line 225 * Company Total line 223
227	Increase with First Re-allocation	$2,806,952	$842,369	$570,487	$1,175,428		$21,805,834	line 220 or line 226 + line 218
228	Revenue to Re-allocate	$18,881	none	none	none		$92,311	line 227 - line 220
229	Test Year Revenue for Re-allocation	NA	$26,060,211	NA	$54,128,002		$505,229,342	line 224
230	Percent Assignment		5.16%		10.71%		100.00%	line 229 / Company Total line 229
231	Second Re-allocation		$4,762		$9,890		$92,311	line 230 * Company Total line 228
232	Increase with Second Re-allocation	$2,788,071	$847,130	$570,487	$1,185,318		$21,805,834	line 227 + line 231 or line 220
233	Revenue to Re-allocate	none	none	none	none		$0	
234								
235								
236								
237								
238								
239								
240	Change from Target Allocation	$382,131	$229,658	-$130,723	$477,009		$0	line 232 - line 218
241								
242	**Base Revenue Requirement**	$8,343,913	$3,653,762	$1,273,942	$6,063,888		$155,425,730	line 213 + line 240
243	Total Revenue Requirement	$49,255,917	$26,907,342	$10,078,604	$55,313,320		$623,063,524	line 217 + line 240
244	Percent Increase	6.00%	3.25%	6.00%	2.19%			(line 243 - line 216) / line 216
245								
246								
247	**RATE DESIGN**							
248								
249	**Proposed Block Sizes**							
250								
251	First Block Size							
252	Winter	NA	NA	NA	NA			See Ex. BSG/JAF-2; Schedule JAF-2-3
253	Summer	NA	NA	NA	NA			See Ex. BSG/JAF-2; Schedule JAF-2-3
254								
255	Test Year Therms							
256	Annual	44,135,406	25,505,268	9,468,031	54,222,227		493,498,312	line 257 + line 258
257	Winter	36,806,379	14,756,628	7,211,204	28,655,953			line 53
258	Summer	7,329,027	10,748,640	2,256,827	25,566,274			line 54
259								
260	Percent of Therms in Proposed 1st Block							See Ex. BSG/JAF-2; Schedule JAF-2-3
261	Winter	100.00%	100.00%	100.00%	100.00%			
262	Summer	100.00%	100.00%	100.00%	100.00%			
263								
264	Proposed First Block Therms							
265	Winter	36,806,379	14,756,628	7,211,204	28,655,953			line 257 * line 261
266	Summer	7,329,027	10,748,640	2,256,827	25,566,274			line 258 * line 262
267								
268	Proposed Second Block Therms							
269	Winter	0	0	0	0			line 257 - line 265
270	Summer	0	0	0	0			line 258 - line 266
271								
272	Base Revenue Requirement	$8,343,913	$3,653,762	$1,273,942	$6,063,888		$155,425,730	line 242
273								

line	Description	Residential Heating Total	Residential Heating R&T-3	Residential Heating (4) Low-Income	Residential Non-Heating Total	Residential Non-Heating R&T-1	Residential Non-Heat (2) Low-Income	Outdoor Lighting	C&I (40) Low Annual High Winter	C&I (50) Low Annual Low Winter	C&I (41) Med. Annual High Winter	C&I (51) Med. Annual Low Winter
274	Proposed Customer Charge	$12.10			$11.60			$2.48	$19.00	$19.00	$65.00	$65.00
275	Customer Charge Revenue	$32,264,577			$4,645,974			$357	$3,803,914	$758,252	$3,652,675	$1,369,745
276	Winter Customer Charge Revenue	$16,231,339			$2,259,135				$1,924,966	$383,249	$1,817,465	$696,670
277	Remaining Revenue	$67,582,822			$1,105,420			$0	$7,402,471	$1,404,741	$9,297,826	$2,801,450
278												
279	Volumetric Revenue Requirement	$67,582,822			$1,105,420			$0	$7,402,471	$1,404,741	$9,297,826	$2,801,450
280	Demand-Based Revenue Requirement	$0			$0			$0	$0	$0	$0	$0
281	Average Volumetric Rate	$0.2727			$0.1728			$0.0000	$0.2936	$0.2679	$0.1717	$0.1311
282	ACS Seasonal Split - Volumetric Req.											
283	Winter Percentage	74.68%			57.15%			70.64%	77.04%	63.39%	90.86%	77.05%
284	Summer Percentage	25.32%			42.85%			29.36%	22.96%	36.61%	9.14%	22.95%
285	Average Volumetric Rate - Winter	$0.2499			$0.1688			$0.0000	$0.2535	$0.2863	$0.1816	$0.1694
286	Average Volumetric Rate - Summer	$0.3733			$0.1785			$0.0000	$0.6265	$0.2410	$0.1113	$0.0745
287	Volumetric Revenue Requirement - Winter	$50,472,308			$631,759			$0	$5,702,719	$890,474	$8,447,725	$2,158,410
288	Volumetric Revenue Requirement - Summer	$17,110,514			$473,661			$0	$1,699,752	$514,267	$850,101	$643,040
289												
290	Unit Marginal Cost ($ / winter therm)	$0.1156			$0.0652			NA	$0.1396	$0.0683	$0.1255	$0.0643
291	Unit Marginal Cost ($ / summer therm)	$0.0640			$0.0307			NA	$0.0804	$0.0324	$0.0711	$0.0306
292	Ratio of Second Block to MC											
293	Winter	1.80			2.30			NA	flat	flat	flat	flat
294	Summer	NA			NA			NA	flat	flat	flat	flat
295												
296	Second Block Rate											
297	Winter	$0.2081			$0.1499			$0.0000	$0.2936	$0.2679	$0.1816	$0.1694
298	Summer	$0.2081			$0.1499			$0.0000	$0.2936	$0.2679	$0.1113	$0.0745
299												
300	Revenue Generated											
301	Annual	$51,571,553			$958,858			$0	$7,402,471	$1,404,741	$9,297,826	$2,801,450
302	Winter	$42,030,763			$561,004			$0	$6,605,801	$833,063	$8,447,725	$2,158,410
303	Summer	$9,540,791			$397,854			$0	$796,670	$571,678	$850,101	$643,040
304												
305	Remaining Revenue											
306	Annual	$16,011,269			$146,562			$0	$0	$0	$0	$0
307	Winter	$8,441,546			$70,755			$0	$0	$0	$0	$0
308	Summer	$7,569,723			$75,807			$0	$0	$0	$0	$0
309												
310	First Block Surcharge											
311	Winter	$0.0960			$0.0465			NA	NA	NA	NA	NA
312	Summer	$0.0960			$0.0465			NA	NA	NA	NA	NA
313												
314	Demand Charge Revenue Requirement											
315	Winter	NA			NA			NA	NA	NA	NA	NA
316	Summer	NA			NA			NA	NA	NA	NA	NA
317												
318	Demand Charge Rates											
319	Winter	NA			NA			NA	NA	NA	NA	NA
320	Summer	NA			NA			NA	NA	NA	NA	NA
321												

line	Description	C&I (42) High Annual High Winter	C&I (52) High Annual Low Winter	C&I (43) Ex. High Ann. High Winter	C&I (53) Ex. High Ann. Low Winter	Special Contract	Company Total	Notes
274	Proposed Customer Charge	$213.00	$213.00	$781.00	$781.00			See Ex. BSG/JAF-2; Schedule JAF-2-2
275	Customer Charge Revenue	$1,583,016	$636,657	$141,361	$624,019		$49,480,547	line 274 * line 27
276	Winter Customer Charge Revenue	$780,006	$325,890	$71,852	$320,210			line 274 * line 28
277	Remaining Revenue	$6,760,897	$3,017,105	$1,132,581	$5,439,869		$105,945,183	line 272 - line 275
278								
279	Volumetric Revenue Requirement	$6,760,897	$3,017,105	$339,774	$1,631,961			For 43 & 53, 30% of the remaining revenues
280	Demand-Based Revenue Requirement	$0	$0	$792,807	$3,807,908			are assigned to the volumetric charges.
281	Average Volumetric Rate	$0.1532	$0.1183	$0.0359	$0.0301			line 279 / line 256
282	ACS Seasonal Split - Volumetric Req.							
283	Winter Percentage	92.57%	79.00%	92.24%	78.91%			(line 141 - line 276) / (line 140 - line 275)
284	Summer Percentage	7.43%	21.00%	7.76%	21.09%			100% - line 283
285	Average Volumetric Rate - Winter	$0.1700	$0.1615	$0.0435	$0.0449			line 287 / line 257
286	Average Volumetric Rate - Summer	$0.0686	$0.0590	$0.0117	$0.0135			line 288 / line 258
287	Volumetric Revenue Requirement - Winter	$6,258,319	$2,383,453	$313,396	$1,287,797			line 283 * line 279
288	Volumetric Revenue Requirement - Summer	$502,578	$633,652	$26,379	$344,163			line 279 - line 287
289								
290	Unit Marginal Cost ($ / winter therm)	$0.1134	$0.0543	$0.1272	$0.0618			line 163
291	Unit Marginal Cost ($ / summer therm)	$0.0634	$0.0254	$0.0669	$0.0272			line 164
292	Ratio of Second Block to MC							
293	Winter	flat	flat	flat	flat			Inputs
294	Summer	flat	flat	flat	flat			
295								
296	Second Block Rate							
297	Winter	$0.1700	$0.1615	$0.0446	$0.0446			line 293 * line 290 or line 287 / line 53
298	Summer	$0.0686	$0.0590	$0.0133	$0.0133			line 294 * line 291 or line 288 / line 54
299								
300	Revenue Generated							
301	Annual	$6,760,897	$3,017,105	$351,981	$1,619,754			line 302 + line 303
302	Winter	$6,258,319	$2,383,453	$321,925	$1,279,268			line 257 * line 297
303	Summer	$502,578	$633,652	$30,056	$340,486			line 258 * line 298
304								
305	Remaining Revenue							
306	Annual	$0	$0	$0	$0			line 307 + line 308
307	Winter	$0	$0	$0	$0			line 287 - line 302
308	Summer	$0	$0	$0	$0			line 288 - line 303
309								
310	First Block Surcharge							
311	Winter	NA	NA	NA	NA			line 307 / line 265
312	Summer	NA	NA	NA	NA			line 308 / line 266
313								
314	Demand Charge Revenue Requirement							
315	Winter	NA	NA	$731,256	$3,004,860			line 280 * line 283
316	Summer	NA	NA	$61,551	$803,048			line 280 - line 315
317								
318	Demand Charge Rates							
319	Winter	NA	NA	$2.1579	$2.1579			line 315 / line 56
320	Summer	NA	NA	$0.6712	$0.6712			line 316 / line 57
321								

Bay State Gas Company
Rate Design

line	Description	Residential Heating Total	Residential Heating R&T-3	Residential Heating (4) Low-Income	Residential Non-Heating Total	Residential Non-Heating R&T-1	Residential Non-Heat (2) Low-Income	Outdoor Lighting	C&I (40) Low Annual High Winter	C&I (50) Low Annual Low Winter	C&I (41) Med. Annual High Winter	C&I (51) Med. Annual Low Winter
322	**Base Rates w/o Low Inc. Discount**											
323												
324	Monthly Customer Charge	$12.10			$11.60			$2.48	$19.00	$19.00	$65.00	$65.00
325	Winter Volumetric Rates											
326	First Block Rate	$0.3041			$0.1964			$0.0	$0.2936	$0.2679	$0.1816	$0.1694
327	Second Block Rate	$0.2081			$0.1499			$0.0	NA	NA	NA	NA
328	Summer Volumetric Rates											
329	First Block Rate	$0.3041			$0.1964			$0.0	$0.2936	$0.2679	$0.1113	$0.0745
330	Second Block Rate	$0.2081			$0.1499			$0.0	NA	NA	NA	NA
331	Demand Rate											
332	Winter	NA			NA			NA	NA	NA	NA	NA
333	Summer	NA			NA			NA	NA	NA	NA	NA
334												
335	**Revenue Generated**											
336	Monthly Customer Charge	$32,264,577			$4,645,974			$357	$3,803,914	$758,252	$3,652,675	$1,369,745
337	Winter Volumetric Rates											
338	First Block Rate	$41,519,029			$331,490			NA	$6,605,801	$833,063	$8,447,725	$2,158,410
339	Second Block Rate	$13,613,764			$307,974			NA	NA	NA	NA	NA
340	Summer Volumetric Rates											
341	First Block Rate	$9,219,088			$287,734			NA	$796,670	$571,678	$850,101	$643,040
342	Second Block Rate	$3,230,942			$178,222			NA	NA	NA	NA	NA
343	Demand Rate											
344	Winter	NA			NA			NA	NA	NA	NA	NA
345	Summer	NA			NA			NA	NA	NA	NA	NA
346	TOTAL PROPOSED BASE REVENUE	$99,847,400			$5,751,394			$357	$11,206,385	$2,162,993	$12,950,501	$4,171,195
347	check	$0			$0			$0	$0	$0	$0	$0
348	**Class Bill Impacts**											
349	Total Test Year Revenue	$328,667,115			$11,003,222			$2,804	$34,227,522	$6,634,448	$62,146,491	$22,411,911
350	Total Proposed Revenue	$338,592,295			$11,663,415			$2,860	$35,579,000	$7,032,515	$64,881,631	$23,756,625
351	check											
352	Percent Change	3.02%			6.00%			1.97%	3.95%	6.00%	4.40%	6.00%
353												
354												
355	**Allocation of Low-Income Discount**											
356	Distribution Rate Base	$228,590,466			$17,817,354			$948	$25,270,507	$4,722,501	$36,540,684	$11,146,787
357	20% Burner-tip Discount Amount (1)			$5,741,226			$148,352					
358	Allocation Percentages	59.18%			4.61%			0.0002%	6.54%	1.22%	9.46%	2.89%
359	Amount Allocated (1)	$3,485,522			$271,677			$14	$385,322	$72,008	$557,168	$169,965
360												
361	Volumetric Surcharge (1)	$0.0141			$0.0425			NA	$0.0153	$0.0137	$0.0103	$0.0080
362												
363	Revised Discount Amount (2)			$5,800,709			$152,308					
364	Amount Allocated (2)	$3,523,066			$274,603			$15	$389,472	$72,784	$563,170	$171,796
365												
366	Volumetric Surcharge (2)	$0.0142			$0.0429			NA	$0.0154	$0.0139	$0.0104	$0.0080
367												
368	Revised Discount Amount (3)			$5,801,350			$152,351					
369	Amount Allocated (3)	$3,523,471			$274,635			$15	$389,517	$72,792	$563,234	$171,815
370												
371	Volumetric Surcharge (3)	$0.0142			$0.0429			NA	$0.0155	$0.0139	$0.0104	$0.0080
372												
373	Proposed Base Revenue		$94,720,421	$2,849,092		$5,694,650	$179,028	$371	$11,595,902	$2,235,785	$13,513,735	$4,343,011
374	Revised Total Revenue		$313,108,980	$23,205,428		$11,176,294	$609,405	$2,874	$35,968,517	$7,105,307	$65,444,865	$23,928,441
375	Total Test Year Revenue		$304,180,734	$24,486,381		$10,364,622	$638,599	$2,804	$34,227,522	$6,634,448	$62,146,491	$22,411,911
376	Revised Percent Change		2.94%	-5.23%		7.83%	-4.57%	2.49%	5.09%	7.10%	5.31%	6.77%

line	Description	C&I (42) High Annual High Winter	C&I (52) High Annual Low Winter	C&I (43) Ex. High Ann. High Winter	C&I (53) Ex. High Ann. Low Winter	Special Contract	Company Total	Notes
322	**Base Rates w/o Low Inc. Discount**							
323								
324	Monthly Customer Charge	$213.00	$213.00	$781.00	$781.00			line 274
325	Winter Volumetric Rates							
326	First Block Rate	$0.1700	$0.1615	$0.0446	$0.0446			line 311 + line 327 or line 297
327	Second Block Rate	NA	NA	NA	NA			line 297
328	Summer Volumetric Rates							
329	First Block Rate	$0.0686	$0.0590	$0.0133	$0.0133			line 312 + line 330 or line 298
330	Second Block Rate	NA	NA	NA	NA			line 298
331	Demand Rate							
332	Winter	NA	NA	$2.1579	$2.1579			line 319
333	Summer	NA	NA	$0.6712	$0.6712			line 320
334								
335	**Revenue Generated**							
336	Monthly Customer Charge	$1,583,016	$636,657	$141,361	$624,019			line 324* line 27
337	Winter Volumetric Rates							
338	First Block Rate	$6,258,319	$2,383,453	$321,925	$1,279,268			line 326 * line 265
339	Second Block Rate	NA	NA	NA	NA			line 327 * line 269
340	Summer Volumetric Rates							
341	First Block Rate	$502,578	$633,652	$30,056	$340,486			line 329 * line 266
342	Second Block Rate	NA	NA	NA	NA			line 330 * line 270
343	Demand Rate							
344	Winter	NA	NA	$739,148	$2,996,969			line 332 * line 56
345	Summer	NA	NA	$69,309	$795,289		$0	line 333 * line 57
346	TOTAL PROPOSED BASE REVENUE	$8,343,913	$3,653,762	$1,301,799	$6,036,031		$155,425,730	sum (lines 336 through 345)
347	check	$0	$0	$27,856	-$27,856			
348	**Class Bill Impacts**							
349	Total Test Year Revenue	$46,467,846	$26,060,211	$9,508,117	$54,128,002		$601,257,691	line 133
350	Total Proposed Revenue	$49,255,917	$26,907,342	$10,106,460	$55,285,464		$623,063,524	line 346 + line 197
351	check							
352	Percent Change	6.00%	3.25%	6.29%	2.14%			(line 350 - line 349) / line 349
353								
354								
355	**Allocation of Low-Income Discount**							
356	Distribution Rate Base	$26,258,806	$11,106,815	$4,945,453	$19,854,998		$386,255,320	COS Input
357	20% Burner-tip Discount Amount (1)						$5,889,578	Schedule JAF-2-5; line 45
358	Allocation Percentages	6.80%	2.88%	1.28%	5.14%		100.00%	line 356 / Company Total line 356
359	Amount Allocated (1)	$400,391	$169,355	$75,408	$302,747		$5,889,578	line 358 * Company Total line 357
360								
361	Volumetric Surcharge (1)	$0.0091	$0.0066	$0.0059	$0.0059			line 359 / line 52
362								
363	Revised Discount Amount (2)						$5,953,017	Schedule JAF-2-5; line 69
364	Amount Allocated (2)	$404,704	$171,180	$76,220	$306,008		$5,953,017	line 358 * Company Total line 363
365								
366	Volumetric Surcharge (2)	$0.0092	$0.0067	$0.0060	$0.0060			line 364 / line 52
367								
368	Revised Discount Amount (3)						$5,953,701	Schedule JAF-2-5; line 95
369	Amount Allocated (3)	$404,751	$171,199	$76,229	$306,043			line 358 * Company Total line 368
370								
371	Volumetric Surcharge (3)	$0.0092	$0.0067	$0.0060	$0.0060			line 369 / line 52
372								
373	Proposed Base Revenue	$8,748,664	$3,824,961	$1,378,028	$6,342,074		**$155,425,723**	JAF-2-5; line 121 or line 346 + line 369
374	Revised Total Revenue	$49,660,668	$27,078,541	$10,182,689	$55,591,507		$623,063,517	JAF-2-5; line 122 or line 350 + line 369
375	Total Test Year Revenue	$46,467,846	$26,060,211	$9,508,117	$54,128,002		$601,257,691	line 349
376	Revised Percent Change	6.87%	3.91%	7.09%	2.70%			(line 374 - line 375) / line 375

line	Description	Residential Heating Total	Residential Heating R&T-3	Residential Heating (4) Low-Income	Residential Non-Heating Total	Residential Non-Heating R&T-1	Residential Non-Heat (2) Low-Income	Outdoor Lighting	C&I (40) Low Annual High Winter	C&I (50) Low Annual Low Winter	C&I (41) Med. Annual High Winter	C&I (51) Med. Annual Low Winter
377												
378	**Proposed Rates w/ Low Income Discount**											
379												
380	Monthly Customer Charge	NA	$12.10	$6.25	NA	$11.60	$6.25	$2.58	$19.00	$19.00	$65.00	$65.00
381	Winter Volumetric Rates											
382	First Block Rate	NA	$0.3183	$0.0708	NA	$0.2393	$0.1158	$0.0	$0.3091	$0.2818	$0.1920	$0.1774
383	Second Block Rate	NA	$0.2224		NA	$0.1928		$0.0				
384	Summer Volumetric Rates											
385	First Block Rate	NA	$0.3183	$0.0708	NA	$0.2393	$0.1158	$0.0	$0.3091	$0.2818	$0.1217	$0.0826
386	Second Block Rate	NA	$0.2224		NA	$0.1928		$0.0				
387	Demand Rate											
388	Winter	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
389	Summer	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
390												
391	**Revenue Proof**											
392												
393	Monthly Customer Charge	NA	$29,648,303	$1,351,381	NA	$4,413,812	$125,088	$371	$3,803,914	$758,252	$3,652,675	$1,369,745
394	Winter Volumetric Rates											
395	First Block Rate	NA	$39,806,670	$1,202,662	NA	$373,665	$32,507	$0	$6,953,397	$876,231	$8,931,502	$2,260,851
396	Second Block Rate	NA	$13,321,133		NA	$366,469		$0	NA	NA	NA	NA
397	Summer Volumetric Rates											
398	First Block Rate	NA	$8,882,550	$295,049	NA	$332,534	$21,433	$0	$838,591	$601,302	$929,559	$712,415
399	Second Block Rate	NA	$3,061,766		NA	$208,170		$0	NA	NA	NA	NA
400	Demand Rate											
401	Winter	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
402	Summer	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
403	TOTAL BASE REVENUE		$94,720,421	$2,849,092		$5,694,650	$179,028	$371	$11,595,902	$2,235,785	$13,513,735	$4,343,011
404												
405	**Class Bill Impacts**											
406												
407	Total Test Year Revenue	NA	$304,180,734	$24,486,381	NA	$10,364,622	$638,599	$2,804	$34,227,522	$6,634,448	$62,146,491	$22,411,911
408	Total Proposed Revenue	NA	$313,108,980	$23,205,428	NA	$11,176,294	$609,405	$2,874	$35,968,517	$7,105,307	$65,444,865	$23,928,441
409												
410	Percent Change	NA	2.94%	-5.23%	NA	7.83%	-4.57%	2.49%	5.09%	7.10%	5.31%	6.77%

line	Description	C&I (42) High Annual High Winter	C&I (52) High Annual Low Winter	C&I (43) Ex. High Ann. High Winter	C&I (53) Ex. High Ann. Low Winter	Special Contract	Company Total	Notes
377								
378	**Proposed Rates w/ Low Income Discount**							
379								
380	Monthly Customer Charge	$213.00	$213.00	$781.00	$781.00			line 324
381	Winter Volumetric Rates							
382	First Block Rate	$0.1792	$0.1682	$0.0506	$0.0506			line 326 + line 371
383	Second Block Rate							line 327 + line 371
384	Summer Volumetric Rates							
385	First Block Rate	$0.0777	$0.0657	$0.0193	$0.0193			line 329 + line 371
386	Second Block Rate							line 330 + line 371
387	Demand Rate							
388	Winter	NA	NA	$2.1579	$2.1579			line 332
389	Summer	NA	NA	$0.6712	$0.6712			line 333
390								
391	**Revenue Proof**							
392								
393	Monthly Customer Charge	$1,583,016	$636,657	$141,361	$624,019			line 27 * line 380
394	Winter Volumetric Rates							
395	First Block Rate	$6,595,858	$2,482,504	$365,207	$1,451,262			line 265 * line 382 or line 53 * line 382
396	Second Block Rate	NA	NA	NA	NA			line 269 * line 383
397	Summer Volumetric Rates							
398	First Block Rate	$569,790	$705,801	$43,602	$493,936			line 266 * line 385 or line 54 * line 385
399	Second Block Rate	NA	NA	NA	NA			line 270 * line 386
400	Demand Rate							
401	Winter	NA	NA	$739,148	$2,996,969			line 56 * line 388
402	Summer	NA	NA	$69,309	$795,289			line 57 * line 389
403	TOTAL BASE REVENUE	$8,748,664	$3,824,961	$1,358,627	$6,361,475		$155,425,723	Sum lines 393 through 402
404								
405	**Class Bill Impacts**							
406								
407	Total Test Year Revenue	$46,467,846	$26,060,211	$9,508,117	$54,128,002		$601,257,691	line 375
408	Total Proposed Revenue	$49,660,668	$27,078,541	$10,163,288	$55,610,908		$623,063,517	line 197 + line 403
409								
410	Percent Change	6.87%	3.91%	6.89%	2.74%		3.63%	(line 408 - line 407) / line 407

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 1, 2005

Responsible: Danny G. Cote, General Manager

RR-DTE-106: Provide a description of the Advantica-Stoner-SynerGEE model to include:

a) how it operates
b) what are the structures
c) what are the parameters that are integral to the model, and
d) what are the outputs from the model

Response:

a) The SynerGEE program models and analyzes networks of pipes, pressure regulators, and valves for the Company's natural gas distribution and transmission lines using complex algorithms and nodal analysis. SynerGEE provides the features of the most advanced pipeline simulation commercially available.

b) The structures include supply points, pressure regulators, and pipelines.

c) The primary parameters in the model are specific gravity, pipeline temperatures and pressures, lengths and internal diameters of the pipeline, pressure regulator characteristics, ambient temperatures, and customer loads.

d) The outputs include reports, graphical views of the entire market, including customer and load information, databases, and specialty plot maps. Depending on the type of analysis being performed, the user selects which output data is viewed (e.g., system pressures, flows, velocities, pipe diameters, etc.).